

UNIVERSITY OF ALBERTA

**Flow of Formation Water in the Alberta Basin
Adjacent to the Rocky Mountains Thrust and Fold Belt,
West-Central Alberta, Canada**

by

Karsten Michael ©

A thesis submitted to the Faculty of Graduate Studies and Research in partial fulfilment
of the requirements for the degree of Doctor of Philosophy.

Department of Earth and Atmospheric Sciences

Edmonton, Alberta

Fall, 2002



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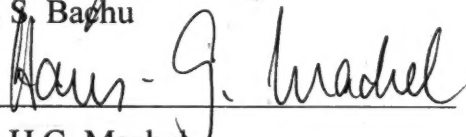
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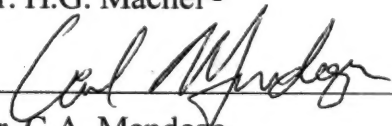
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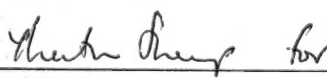
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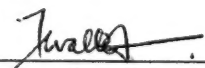
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Abstract

The hydraulic communication between the deformed and undeformed parts of the Alberta Basin, as well as the vertical hydraulic communication, flow-driving mechanisms, and the evolution of formation waters in the deep basin, are still poorly understood. Therefore, flow patterns of formation waters in west-central Alberta in the vicinity of the Rocky Mountains were investigated using publicly-available, standard industry, chemical analyses of formation waters and fluid pressure data from drillstem tests.

Hydraulic analysis of DST data shows that only flow in the post-Colorado aquifers has adjusted to local to regional-scale ground surface topography. Flow in the Colorado and Mannville (Lower Cretaceous) aquifers is mostly towards sinks created by erosional and post-glacial rebound of the intervening shales, and towards the receding hydrocarbon-saturated regions along the Rocky Mountains. The Jurassic to Cambrian aquifers appear to be influenced only marginally by mixing with freshwater, carried predominantly by a long-range, gravity-driven flow system originating in the south of the study area in Montana. A contribution of freshwater from the adjacent Rocky Mountains appears to be restricted to channelled flow along relatively high-permeable strata, i.e., Middle Devonian platform margins. The main reasons for the isolation of "relict" formation waters in the Jurassic-Cambrian aquifers are: 1) effective confining aquitards; 2) hydrocarbon-saturated zones in the overlying Cretaceous; and 3) buoyancy effects between less saline formation water located downdip of heavy connate brine.

Based on salinity and Na/Cl-ratios, the formation waters in west-central Alberta can be grouped with partial overlap into: 1) mainly meteoric, Tertiary-Upper Cretaceous

groundwater (TDS < 15 g/L, Na/Cl_{molar}: 0.9-1.5); 2) Lower Cretaceous waters with various degrees of mixing between seawater and meteoric water (TDS <100 g/L, Na/Cl_{molar}: 0.9-1.5); 3) Jurassic-Mississippian, evaporated seawater that was altered by halite dissolution and dolomitization (TDS: 50-160 g/L, Na/Cl_{molar}: 0.8-1.0); and 4) Devonian-Cambrian, evaporated seawater that underwent a high degree of water-rock interaction, i.e., dolomitization, halite dissolution, and predominantly albitization of feldspar (TDS: 125-300 g/L, Na/Cl_{molar}: 0.5-0.9).

The analysis of fluid and pressure distributions in the Tertiary-Cretaceous succession in west-central Alberta demonstrates that the hydrocarbon-saturated zones have a major effect on basin-scale fluid flow in the Alberta Basin, forming both, an effective barrier and a sink for formation water flow. Furthermore, the integration of hydrodynamics and formation water chemistry shows evidence of only marginal mixing of formation waters with meteoric water in the deeper parts of the basin.

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CHAPTER 1: INTRODUCTION

1.1 Rationale

Formation water is an important agent in most geological processes and regional water flow affects the formation and distribution of mineral and hydrocarbon deposits during the evolution of sedimentary basins (e.g., Garven, 1995; Tóth, 1999; Ingebritsen and Sanford, 1998). The two basic aspects of the influence of formation water in the subsurface are the interaction between water and the surrounding rock framework, and water flow as a transport and distribution mechanism (Tóth, 1999). Therefore, studying the hydrochemical and hydrodynamic patterns is essential for understanding the spatial and temporal distribution of fluids, solutes and precipitates in sedimentary basins, and for the emplacement of energy and mineral resources.

The Alberta Basin in western Canada (Fig. 1.1a) is a representative example of a foreland basin that has been studied extensively. The Alberta Basin, spanning from $\sim 49^{\circ}\text{N}$ to $\sim 61^{\circ}\text{N}$ and from $\sim 109^{\circ}\text{W}$ to the Rocky Mountains, consists of a northeasterly tapering wedge of sedimentary rocks that varies in thickness from > 6000 m in the west, at the thrust and fold belt of the Rocky Mountains, to zero in the northeast, at the exposed Precambrian Shield (Fig. 1.1b). Ongoing erosion since the Eocene created the current topographic relief, with elevations ranging in the undeformed part of the Alberta Basin from > 1400 m above sea level (a.s.l.) in the west-southwest to ~ 200 m a.s.l. at the Great Slave Lake in the north-northeast.

Formation water flow and hydraulic characteristics of the rock framework affect(ed) the migration and accumulation of hydrocarbons, terrestrial heat flow, ore genesis, and the suitability for deep waste disposal in the Alberta Basin (Bachu, 1999). Many basin- to regional scale hydrogeological studies have been performed during the last four decades that have led to a significant improvement in the understanding of the hydrogeological regime in the basin.

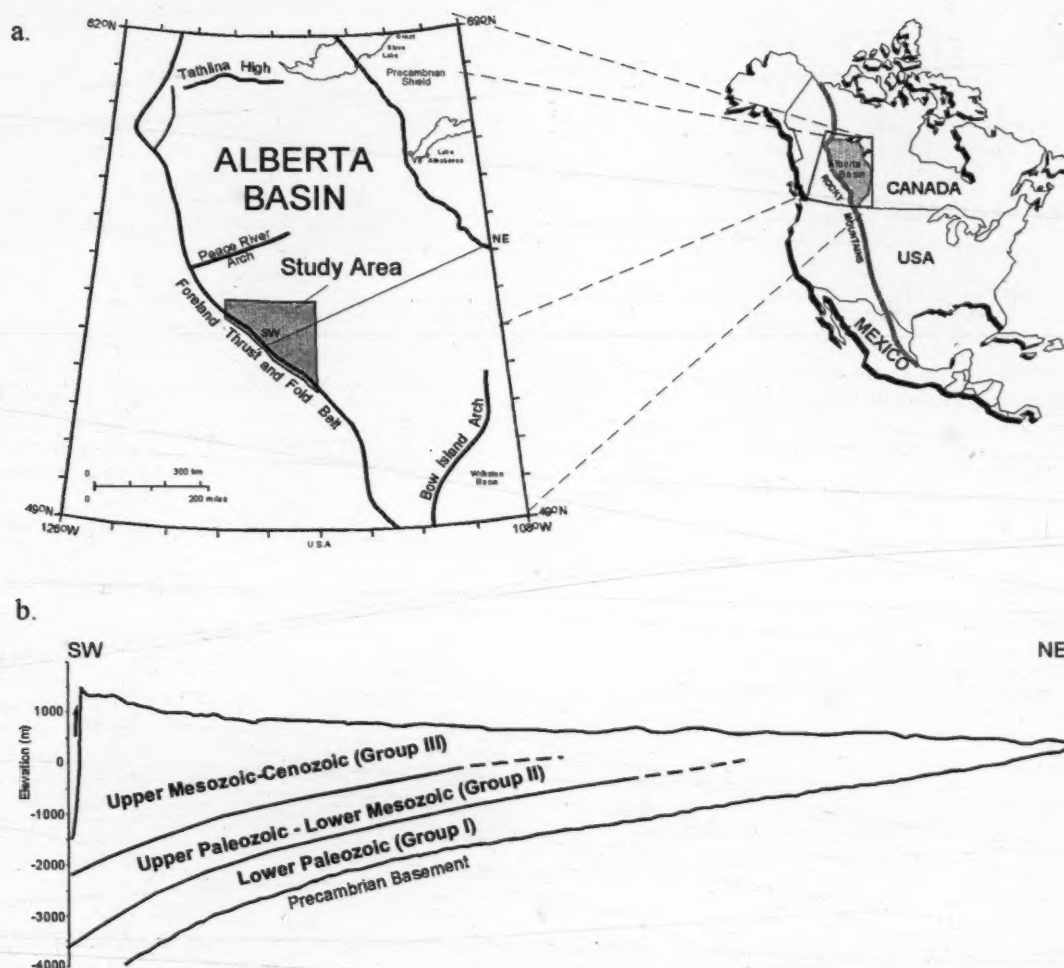


Figure 1.1: a) Location of the study area in the Alberta Basin, and b) cross section showing general subdivision of the sedimentary succession into three main hydrostratigraphic groups (after Tóth, 1978; Hitchon et al., 1990).

Following Tóth (1963), Hitchon (1969) developed the first concept of a basin-wide, topography-driven flow system in the Alberta Basin. Further studies revealed much greater complexity of the hydrostratigraphy and flow patterns in the basin, which led to the currently accepted model of formation water flow (Bachu, 1995a and references therein). According to this conceptual model, flow systems of various scales, and in

different parts of the Alberta Basin, are driven by topography, erosional rebound, and/or past tectonic compression, and may interact with each other to varying degrees (Bachu 1995a; 1999). Although the understanding of regional-scale flow in the basin is relatively high, several issues regarding the basin- to regional-scale hydrogeology in the Alberta Basin remain to be further investigated. These include: 1) focused flow along high-permeability pathways, 2) the degree of hydraulic communication between the deformed and undeformed parts of the basin, 3) hydraulic communication between the crystalline basement and the sedimentary succession, 4) the interaction between the hydrocarbon- and water-saturated parts, and 5) the recharge of and the nature of the flow-driving mechanisms in deep-basin aquifers (Bachu, 1999).

The deeper parts of the Alberta Basin near the deformation front of the Rocky Mountains are of particular interest because this region is currently an exploration target for natural gas in the Devonian and for coal bed methane in the Cretaceous systems. It was proposed that tectonic expulsion of fluids during the Laramide orogeny has affected flow in the Devonian aquifers in west-central Alberta (Machel et al., 1996; Machel and Cavell, 1999). Although numerical studies by Ge and Garven (1989, 1994) suggest that the resulting excess pressures should have dissipated after several million years, relatively weak remnants of the tectonically induced flow might still be active in this part of the Alberta Basin (Bachu, 1995a).

Hydrocarbons displaced formation water, to form hydrocarbon-saturated regions in the Cretaceous succession along the Rocky Mountain thrust and fold belt, downdip of the water-saturated parts of the basin (Masters, 1979). Yet, it has not been investigated how these hydrocarbon accumulations affect the present regional flow of formation waters. Currently, erosional rebound of shales is believed to be the main mechanism that creates observed underpressures in Cretaceous aquifers (Bachu, 1995a; Parks and Tóth, 1995; Bekele et al., 2000).

The extent of mixing of connate formation water with meteoric recharge is of interest from a scientific point of view. Especially, the hydraulic communication of meteoric recharge in the Rocky Mountain thrust and fold belt with the undeformed parts of the Alberta Basin is not well understood. While basin-scale recharge from the thrust and fold belt was shown for the northern part of the Alberta Basin (Bachu, 1997), lack of hydraulic communication was inferred south of the Peace River region (Fig. 1.1) on the basis of flow patterns (Bachu, 1995a; 1999), and it was also suggested in a hydrogeological study of Devonian aquifers in southern Alberta (Wilkinson, 1995). On the other hand, freshwater is believed to have infiltrated down to Mississippian aquifers via convoluted pathways in the over-thrust fault systems (Underschultz and Bartlett, 1999).

1.2 Study Area

The location of the study area (Fig. 1.2) was chosen to investigate specifically the hydrogeology of strata suspected to be influenced by tectonic fluid expulsion (Bachu 1995a, Machel and Cavell, 1999) in the area of the Upper Devonian Southesk-Cairn carbonate complex, and to elucidate the influence of 'deep basin' hydrocarbon accumulations (Masters, 1979) on formation water flow in the Cretaceous succession. Also, due to the vicinity of the study area to the Rocky Mountain thrust and fold belt, a study of the hydrogeology in this area could produce new information on the hydraulic communication between deformed and undeformed parts in this part of the Alberta Basin.

The boundaries of the study area are defined by 52.3° - 55° latitude N and 116° - 120° longitude W, and by the SE-NW trending deformation front of the Rocky Mountains in the west (Fig. 1.2). In places, the hydrogeological interpretations are extended into the foothills region, where hydrogeological data are available. The study area comprises 510 townships and covers approximately 50,000 km².

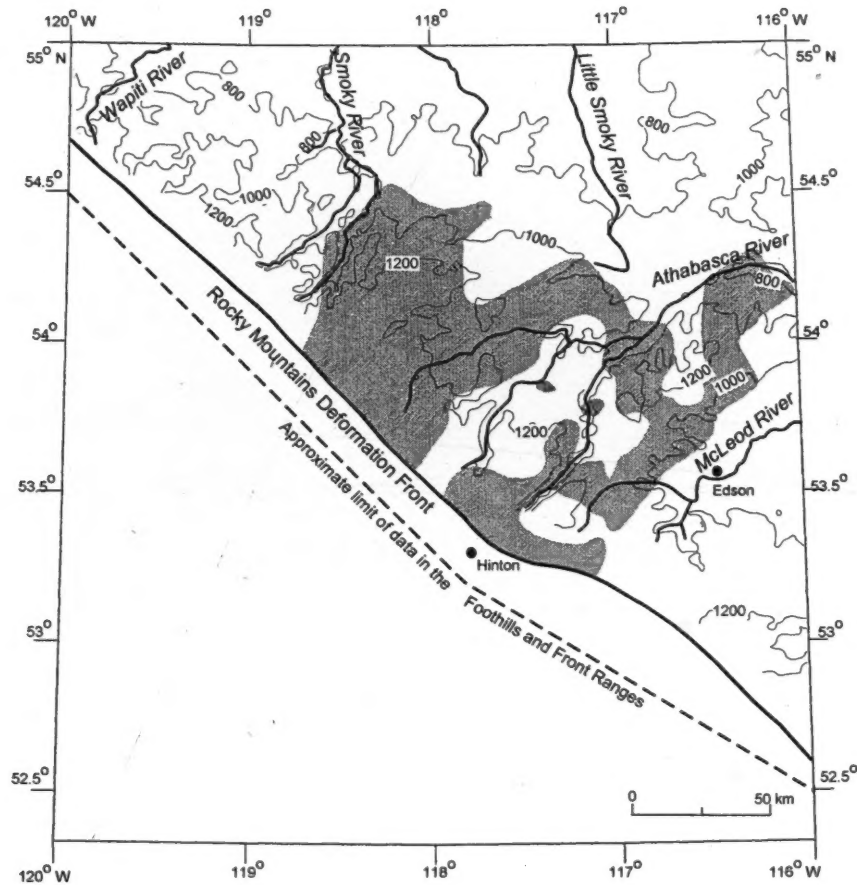


Figure 1.2: Topographic map of the study area, showing outline of the Devonian Southesk-Cairn Complex (grey shading) in the subsurface (outline from Buschkuehle and Machel, 2001).

The topography in the study area ranges from over 1400 m in the foothills region down to 700 m above the sea level in the plains. Major population centers are Hinton in the foothills region and Edson near the eastern boundary. The largest rivers, flowing across the study area from the mountains to the northeast, are the Athabasca River in the south and the Smoky River in the north.

1.3 Previous Work

The Alberta Basin is an important petroleum province, with extensive exploration and exploitation using more than 300,000 wells drilled since the early 1950s. Thus, there is an extensive collection of geological as well as hydraulic and hydrochemical data, which were used in various hydrogeological studies to interpret regional fluid flow in the basin. The locations of the studies that were fundamental for the development of hydrogeological concepts in the basin and those that are most relevant with respect to their geographic location and hydrogeological results as related to this study are shown in Figure 1.3.

Hydrochemistry of Formation Waters

Hitchon and Friedman (1969), Billings et al. (1969) and Hitchon et al. (1971) concluded that the formation waters in the Alberta Basin represent ancient seawater that has been diluted and/or concentrated by meteoric water and membrane filtration, respectively. Their study was based on the distribution of major ions, alkali metals, and stable isotopes of hydrogen and oxygen in formation waters. Schwartz et al. (1981) confirmed the mixing with present-day meteoric water in the Taber area in southern Alberta and depicted flow patterns in Cretaceous aquifers, using stable isotope data of hydrogen and oxygen. Cl^{36} -dating of Late Cretaceous Milk River formation waters estimated the residence time of these waters to be approximately 2 m.y. (Phillips et al., 1986). Spencer (1987) characterized the majority of Devonian formation waters as $\text{Ca} - \text{Cl}$ brines that initially formed from the evaporation of seawater and were modified by water - rock interaction with basement rocks and mixing with freshwater. Also, the pervasive, replacive dolomitization of limestones in the Devonian succession indicates that large amounts of fluids must have passed through these rocks (e.g., Machel and Mountjoy, 1987; Mountjoy et al., 1999), which probably has significantly influenced the formation water chemistry.

To date the most comprehensive hydrochemical study in the Alberta Basin is by Connolly et al. (1990a,b). These authors were able to distinguish between three groups of formation waters (Tab. 1.1), using comprehensive hydrochemical data (major ions, isotopes, organic chemistry) from throughout the entire stratigraphic column, in a local-to regional-scale study in central Alberta (Fig. 1.3).

Era	Hydrochemistry (Connolly et al. 1990)	Regional Hydrogeology (Tóth, 1978)	Basin Hydrogeology (Bachu, 1995a)
Tertiary	Group 3 Dilute, meteoric waters	Group III Local flow system	Post-Jurassic - topography-driven flow (local-scale) - flow driven by erosional rebound (regional-scale)
Cretaceous	Group 2 Brines isolated from present meteoric recharge (in clastics)		
Jurassic			
Triassic		Group II Intermediate flow system	
Permian			
Mississip.			
Devonian	Group 1 Brines isolated from present meteoric recharge (in carbonates)		Pre-Cretaceous - topography-driven flow (basin-scale) - tectonically-induced flow with buoyancy effects (basin-scale)
Cambrian		Group I Regional flow system	

Table 1.1: Various hydrogeological sub-divisions of the Alberta Basin.

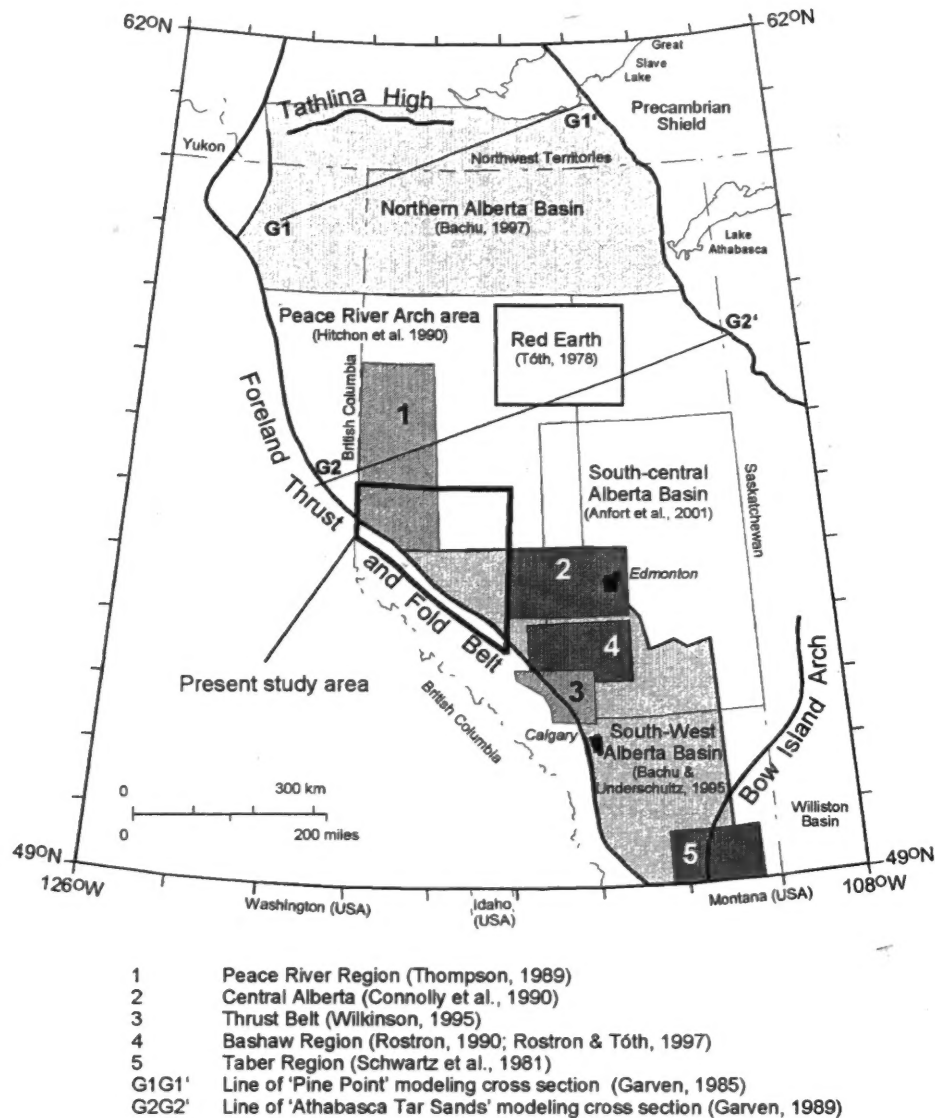


Figure 1.3: Location of former local- to regional-scale hydrogeological studies in the Alberta Basin that are relevant to the present study.

Connolly et al. (1990a,b) suggested that water from deep, hydraulically isolated, carbonate (Group 1) and sandstone (Group 2) aquifers is represented by evaporated seawater that was diluted by post-Laramide meteoric water, whereas Group 3 is characterized by dilute, meteoric waters from Upper Cretaceous aquifers. However, the

above study covered only a part of the Alberta Basin, and the evolution history of formation waters for the remainder of the basin has not yet been clarified.

Flow of Formation Waters

An earlier interpretation of the flow in the Alberta Basin suggested a basin-wide, topography-driven flow system (Fig. 1.4) that is recharged in the Rocky Mountain Foothills in the southwest, channeled updip mainly along Devonian carbonate aquifers, and discharges in the northeast along the "feather-edge" of the basin (Hitchon, 1969, 1984). This interpretation was used to explain the Pine Point Pb-Zn and the Athabasca oil sands deposits in the Alberta Basin, whereby a relatively high permeability was assumed for the Upper Devonian carbonates that were thought to be the major regional aquifer (Hitchon, 1984; Garven, 1985; 1989). One implication of this hydrogeological interpretation is that the basin-scale flow system should have flushed the connate brines from the deep Devonian aquifers within only about two million years, as shown by numerical models of topography-driven flow (Deming and Nunn, 1991; Adams et al. 2000). However, the presence of high-salinity brines in the Paleozoic formations indicates that the basin has not been flushed, and that a single, basin-scale topography-driven flow system, as described above, is not likely to be active in the Alberta Basin (Bachu, 1995a).

Tóth (1978) in the Red Earth region and Hitchon et al. (1990) in the Peace River Arch area (Fig. 1.3) divided the stratigraphic succession into three main hydrogeological groups: I) Lower Paleozoic, II) Upper Paleozoic-Lower Mesozoic, and III) Upper Mesozoic-Cenozoic (Fig. 1.1b), each separated by regional aquitards. According to their interpretation, the flow systems in Groups II and III generally have adjusted to the overlying intermediate- and local-scale ground surface topography, respectively. However, some areas may contain superimposed local flow systems originating in the Pleistocene-Holocene (Tóth, 1978). Flow systems in Group I were interpreted to be maintained by "relict energy differences" originating in the Pliocene, with the flow in a

transient process of equilibrating to the present-day ground surface (Tóth, 1978; Tóth and Millar, 1983; Tóth and Corbet 1986). On the other hand, Hitchon et al. (1989; 1990) attributed flow patterns in Group I that are not in equilibrium with the ground surface to be caused by the drainage effect of the underlying, high-permeable Grosmont carbonate aquifer with basin-scale northeastward flow. Subsequent studies have shown that the erosional rebound of shales is the most likely mechanism creating underpressures in Group III aquifers (Corbet and Bethke, 1992; Parks and Tóth, 1995; Bachu and Underschultz, 1995), as opposed to the former concept of “relict pressures”.

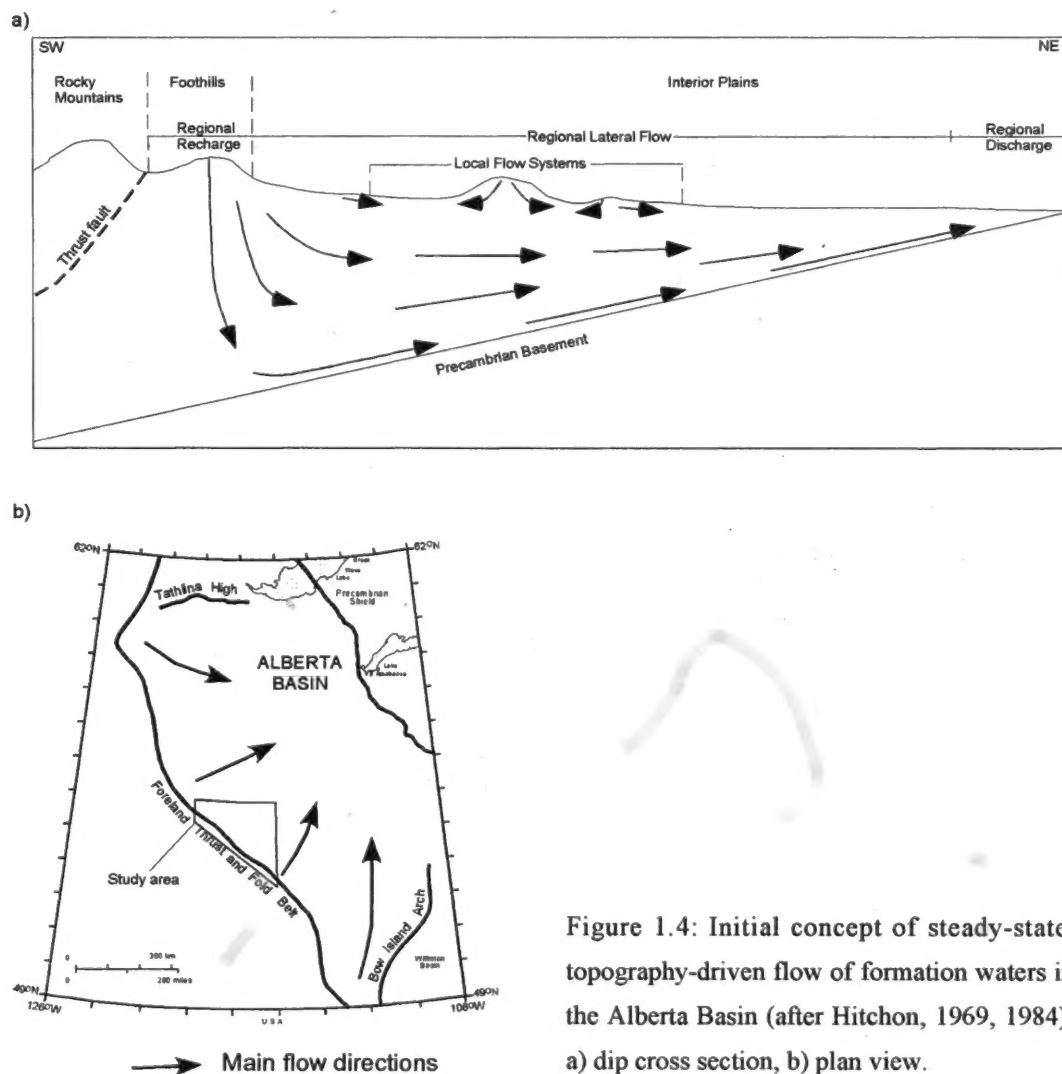


Figure 1.4: Initial concept of steady-state, topography-driven flow of formation waters in the Alberta Basin (after Hitchon, 1969, 1984): a) dip cross section, b) plan view.

At present, different driving mechanisms are thought to drive flow in two megahydrostratigraphic groups (MHG), the pre-Cretaceous and post-Jurassic (Bachu, 1995), in various parts of the Alberta Basin (Fig. 1.5, Tab. 1.1). In the northern part, flow in the entire stratigraphic succession is driven by ground surface topography in local to regional systems. The general flow direction is northeastward, with recharge in the thrust and fold belt of the Rocky Mountains and discharge at the Great Slave Lake, where the respective aquifers subcrop beneath the Quaternary cover (Bachu, 1997).

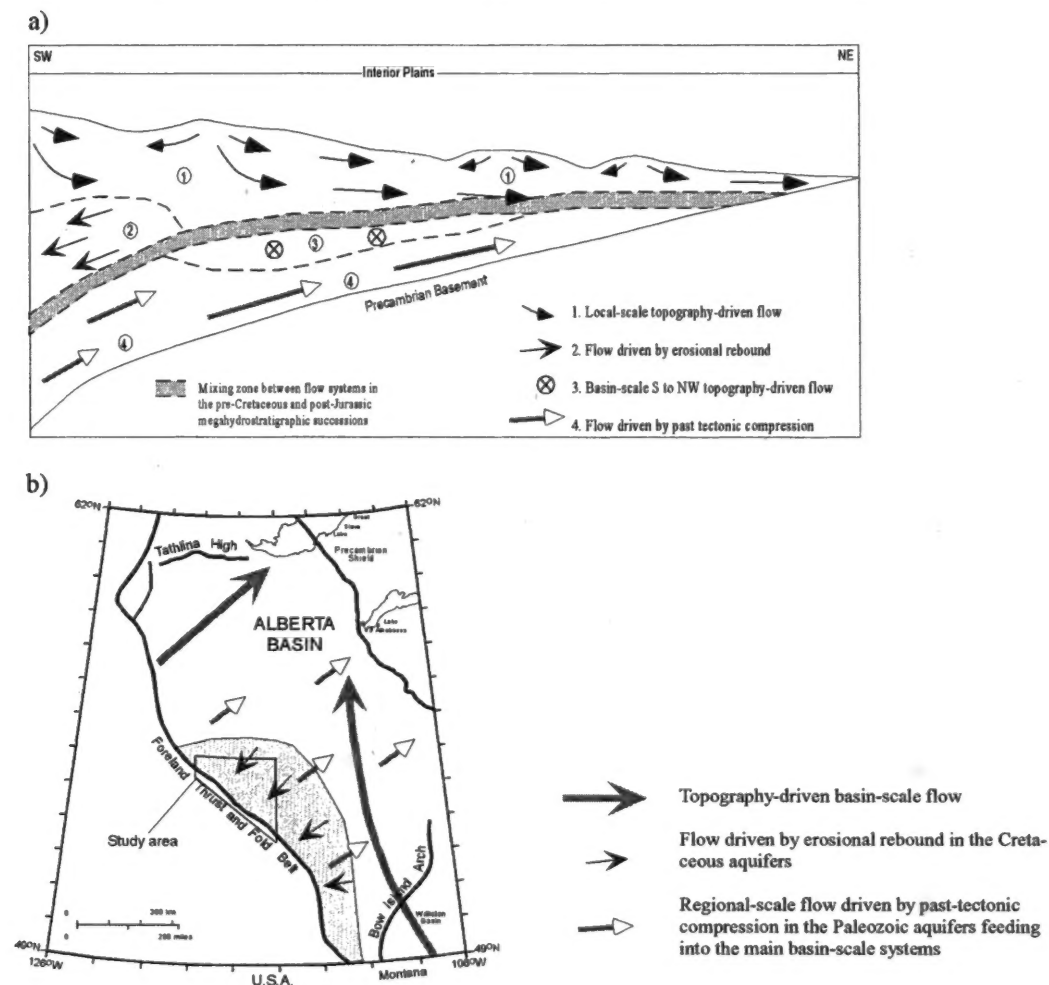


Figure 1.5: Recent diagrammatic representation of flow systems and pattern in the Alberta Basin after a compilation of hydrogeological studies by Bachu (1995a; 1999, and references therein): a) dip cross section, and b) plan view.

In contrast, in the southern and central parts of the basin the general flow direction in the pre-Cretaceous MHG is northward, driven also by topography, with recharge occurring in areas of Devonian outcrop at high elevations in the south in Montana and discharge at formation outcrop in the north along the Peace River (Bachu, 1995a; 1999; Anfort et al., 2001). Hydraulic heads in the various aquifers in the pre-Cretaceous MHG in the west-central part of the basin indicate east-northeastward flow from the Rocky Mountain deformation front (Hitchon et al., 1990), but relatively high formation water salinity suggests that the flow in these aquifers is disconnected from any mixing with low-salinity meteoric recharge (Bachu, 1995a). Also, a study of flow in Devonian aquifers in southern Alberta revealed that flow systems in the thrust and fold belt of the Rocky Mountains appear to be disconnected from flow systems in the adjacent undeformed part of the basin (Wilkinson, 1995). Past tectonic compression was proposed as the mechanism that drives the flow in this region (Bachu, 1995a; 1999; Machel et al., 1996), but strontium isotope studies indicate that fluids expelled by this mechanism migrated only 100 km from the deformation front (Machel and Cavell, 1999; Buschkuehle and Machel, 2001). In addition, numerical modeling studies suggest that excess pressures generated by tectonic loading would have occurred in pulses and dissipated after several million years (Ge and Garven, 1989; 1994). On the other hand, freshwater is believed to have infiltrated down to Mississippian aquifers via convoluted pathways in the over-thrust fault systems (Underschultz and Bartlett, 1999). Thus, the flow-driving mechanism(s) of brines in the pre-Cretaceous MHG in the west-central part of the basin is not yet understood.

Fluid flow in the lower part of the post-Jurassic MHG in the northern part of the Peace River region is driven by regional- and local-scale topography, respectively, while flow in the southern part is hindered by "deep basin" gas accumulations that act as a barrier to fluid flow (Thompson, 1989). Recharge of the lower Cretaceous by meteoric water from the topographic highs in the Rocky Mountain thrust and fold belt north of the Peace River (Thompson, 1989) is consistent with basin-scale recharge from the thrust and fold belt in the northern part of the Alberta Basin (Bachu, 1997). Lack of hydraulic communication

was inferred south of the Peace River region on the basis of flow patterns (Bachu, 1995a, 1999). The observed underpressuring and the flow in the Cretaceous units in the central and southern parts of the basin were attributed to erosional rebound in thick shale successions after the peak of the Laramide orogeny (Corbet and Bethke, 1992; Bachu, 1995a; Bachu and Underschultz, 1995; Parks and Tóth, 1995; Bekele et al., 2000).

Aside from the basin- to regional separation of various hydrostratigraphic groups in the Alberta Basin by competent aquitards, cross-formational flow may occur where intervening aquitards are locally thin or absent. Locations with vertical hydraulic communication were identified previously across the thin Cretaceous Clearwater and the Devonian Watt Mountain aquitards in northeastern Alberta (Bachu and Underschultz, 1993); across the Devonian Calmar aquitard in southeastern Alberta (Rostron and Tóth, 1997; Anfort et al., 2001); and in places where the Ireton aquitard is thin or absent above reef complexes in the Cheddarville and Bashaw areas in southern Alberta (Wilkinson, 1995; Rostron et al., 1997; Anfort et al., 2001) and along the Rimbey-Meadowbrook reef trend further to the north (Bachu and Underschultz, 1993). The identification of areas of cross-formational flow is important, because they are potential pathways for hydrocarbon migration.

1.4 Thesis organization and main objectives

This thesis investigates the regional hydrogeology in the west-central part of the Alberta Basin and is organized into eight chapters. The first four chapters establish the methodological and geological framework of this study:

- former hydrogeological work in the Alberta Basin, resulting concepts, remaining issues, and main objectives and rationale for this study (this chapter);
- theoretical principals of formation water flow in sedimentary basins (Chapter 2);
- data processing, culling methods and data accuracy (Chapter 3);
- regional geological framework (Chapter 4).

The hydrogeological observations and interpretations are presented in the last four chapters. The main objectives are:

- to investigate the distribution and interaction of hydrocarbon- and water-saturated regions and the extent of topography-driven flow versus flow driven by erosional rebound in the Tertiary-Cretaceous succession (Chapter 5);
- to establish the origin and flow-driving mechanisms of formation water in the Jurassic-Mississippian succession (Chapter 6);
- to investigate the possibility of tectonically-induced flow, the displacement of connate brines by meteoric waters, and preferential flow paths in the Cambrian-Devonian succession (Chapter 7);
- to characterize the interaction of flow systems and evolution of formation waters in the entire succession from the ground surface to the Precambrian basement, and to compare the results to the currently accepted interpretation of formation water flow in the Alberta Basin (Chapter 8).

CHAPTER 2: REPRESENTATION METHODS FOR FLOW OF AQUEOUS FLUIDS IN SEDIMENTARY BASINS

2.1 Introduction

The purpose of this chapter is to find a suitable method for accurately interpreting the flow of formation waters in the west-central part of the Alberta Basin, using pressure and hydrochemical data collected by the petroleum industry. The ability to evaluate the direction and rate of flow depends on the availability, distribution and quality of the required hydrogeological data, knowledge of the aquifer geometry, and on the understanding of driving mechanisms for formation water flow in sedimentary basins. Therefore, the first section of this chapter introduces the physical principles and equations for fluid flow and how they account for the various flow-driving mechanisms.

Traditionally, freshwater hydraulic heads have been used to interpret fluid flow in sedimentary basins. However, there are errors associated when applying this method to the case of variable-density fluid flow in sloping aquifers (Luszczynski, 1961; Davies, 1987; Dorgarten and Tsang, 1991; Bachu, 1995b). Therefore, limitations for the usage of hydraulic heads and possible alternatives are evaluated in the second section of this chapter.

In contrast to near-surface groundwater flow, which is almost solely driven by gravity in most cases, regional flow in sedimentary basins is driven by a combination of various mechanisms such as: a) topography (gravity), b) sediment compaction, c) tectonic loading, d) erosional rebound, e) buoyancy, f) overpressures due to hydrocarbon generation, and g) osmosis or mineral phase changes (e.g., Kreitler, 1989; Garven, 1995; Ingebritsen and Sanford, 1998). During the geologic history of a sedimentary basin various driving mechanisms may dominate in various stages of basin evolution. Because of the large size of sedimentary basins, properties of the fluids and solids can also vary

significantly in space and with time. These changes have to be considered when interpreting present-day hydrogeological data. The individual driving mechanisms, as well as fluid and rock properties with respect to their influence on basin-scale fluid flow are reviewed in Appendix A.

2.2 Equations describing flow in sedimentary basins

Fluid flow in sedimentary basins can be described by three equations based on the conservation laws for mass and energy and on the empirical equation of Darcy's Law (Eqs. 2.1 – 2.3). Hubbert (1940) defined fluid flow in porous media as a mechanical process that is dominantly influenced by friction, and during which the mechanical energy initially contained in the fluid is continuously dissipated along the flow path from high to low energy potentials. The energy of a fluid is defined by its relative elevation (potential energy), the fluid pressure at that elevation (pressure energy), and the kinematic energy so that, for a non-compressible fluid and a conservative flow field, the law for the conservation of energy can be expressed by (Hubbert, 1940):

$$\Delta \left(gz + \frac{p}{\rho} + \frac{v^2}{2} \right) + \Delta \epsilon = 0 \quad (2.1a)$$

where g = acceleration due to gravity (m/s^2), z = elevation (m), p = fluid pressure (Pa), ρ = fluid density (kg/m^3), v = flow velocity (m/s), $\Delta \epsilon$ = dissipated energy per unit mass (m^2/s^2) due to friction along the flow path.

The kinematic energy term ($v^2/2$) is negligible with respect to the other terms, because of the generally low velocities of groundwater flow, and Equation 2.1a simplifies to:

$$\Delta \left(gz + \frac{p}{\rho} \right) + \Delta \epsilon = 0 \quad (2.1b)$$

The combination of the two terms within the brackets in this relation explicitly shows that fluids flow from high to low energy levels, and not just from high to low pressures. Therefore, fluid pressure, fluid density and the measurement elevation are the three basic parameters for analyzing the energy available to cause flow of formation water.

Darcy's Law is an empirical formulation for the law of momentum conservation for flow in porous media. For coupled flow and a reference state of formation water regarding fluid density and viscosity for respective pressure-temperature-concentration conditions, Darcy's Law can be expressed as (Bear, 1972; de Marsily, 1986; Bachu, 1995b):

$$q = -\frac{k \rho_0 g}{\mu} \left[\nabla \left(\frac{p}{\rho_0 g} + z \right) + \frac{\rho - \rho_0}{\rho} \nabla z \right] - K_T \nabla T - K_C \nabla C \quad (2.2)$$

where q = specific discharge (m/s), k = permeability (m^2), ρ = fluid density (kg/m^3), ρ_0 = reference density (kg/m^3), μ = fluid viscosity (Pa s), T = temperature ($^{\circ}C$), C = concentration (kg/kg), and K_T , K_C = phenomenological coefficients representing the hydraulic conductivity to thermal ($m^2/^{\circ}C/s$) and chemical osmosis (m^2/s), respectively.

Equation 2.2 shows that flow of a variable-density fluid is driven by a combination of forces resulting from potential differences, buoyancy, and thermal and chemical osmosis. The potential differences are a result of pressure and/or elevation (topography) differences that combine to the expression of the "hydraulic gradient" for a fluid with

$$\text{constant density: } \nabla H_0 = \nabla \left(z + \frac{p}{\rho_0 \cdot g} \right), \quad (2.3)$$

$$\text{where } H_0 = z + \frac{p}{\rho_0 \cdot g} \quad (2.4)$$

is defined as 'hydraulic head' in units of metres above mean sea level (e.g., Hubbert, 1956).

The density variations in the fluid are accounted for in the buoyancy term: $\frac{\rho - \rho_0}{\rho} \nabla_z$.

Thermal and chemical osmosis are generally negligible, because the phenomenological coefficients K_T and K_C are much smaller than the hydraulic conductivity K_H (Bear, 1972; de Marsily, 1986; Neuzil, 1986), where $K_H = \frac{k \rho_0 g}{\mu}$. Nevertheless, the temperature distribution and the concentration of solutes affect the fluid density and may cause buoyancy effects.

The distribution of the permeability k of the rock framework (Eq. 2.2), hence the hydraulic conductivity K_H , largely controls pressure transmission and fluid flow in sedimentary basins. In the most generalized form the permeability is represented by a second-rank symmetric tensor (Bear, 1972), but the nine components reduce to three if the principal directions of anisotropy coincide with the respective coordinate axes in three dimensions. This is usually considered to be the case for layered sedimentary sequences, with a horizontal to vertical anisotropy between 1 : 1 and 10 : 1 (Freeze and Cherry, 1979, p. 32).

The law of mass conservation of the fluid contained in a volume unit of a porous medium can be expressed in the form of the continuity equation (de Marsily, 1986):

$$\nabla \cdot (\rho \bar{q}) + \frac{\partial}{\partial t} (\rho n) + \rho \xi = 0 \quad (2.5)$$

where n = porosity (-), ξ = source term (-).

Combining Darcy's Law (Eq. 2.2) and the continuity equation (Eq. 2.5) results in various forms of a partial differential equation, generally known as the diffusion equation, which describes various types of flow, and which can be solved as an initial and boundary-value problem. A comprehensive form of the diffusion equation for transient, saturated flow in a heterogeneous, anisotropic porous medium can be found in Neuzil (1995), which in addition to the hydraulic driving force accounts for changes in pressures as a result of: a)

changes in total stress due to compaction, decompaction, or tectonic loading, b) changes in porosity due to mineral dissolution and precipitation, and/or density changes caused by mineral and hydrocarbon phase changes, c) thermal expansion/shrinking of the fluid and rock matrix, and d) external fluid sources, such as derived from magmatic intrusions or the basement (Bredehoeft and Hanshaw, 1968; Neuzil, 1995). The effects on fluid pressure described by the last four processes (a-d) can be maintained only over a geological significant period of time in a low-permeability environment (Bredehoeft and Hanshaw, 1968; Neuzil, 1995).

Darcy's Law and the diffusion equation can be solved quantitatively only with numerical models, because many variables vary spatially and in time. These models typically discretize a study area into blocks and time steps in which the variables are assumed to be constant. For each block and time step the equation has to be solved separately. A comprehensive discussion of groundwater modeling in sedimentary basins is beyond the scope of this thesis and the reader is referred to corresponding literature on that topic (e.g. Bethke, 1985, 1989; Deming and Nunn, 1991; Garven, 1985, 1989; Ge and Garven, 1992; Nunn and Deming, 1991; Person et al., 1996).

Only present-day pressure and hydrochemical data are available for this study, hence a more qualitative approach has to be taken to analyze and interpret fluid flow. Therefore, the next section discusses representation methods that only require data sets of pressure, density, and aquifer geometry.

Fluid Potential and Hydraulic Head

The most important method to represent and interpret regional-scale fluid flow in the subsurface is by using potentiometric surface maps of hydraulic heads to infer flow direction and strength. Hydraulic heads are calculated according to Equation 2.4 and flow is inferred to occur from high to low hydraulic heads. Although the use of hydraulic heads in potentiometric surface maps is a powerful and often the only available tool to

investigate fluid movement in the subsurface, it is applicable only under certain conditions.

To infer fluid flow from differences in hydraulic head it must be shown that H_0 is indeed a parameter that represents the energy potential of the fluid. Hubbert (1940) defined the fluid potential per unit mass as (see also Eq. 2.1a):

$$\Phi = gz + \frac{v^2}{2} + \int_{p_0}^p \frac{dp}{\rho} \quad (2.6)$$

For a fluid potential to exist, the work along any distance, ds , in a closed path, in the flow field must equal zero. Neglecting the kinetic energy term, justified for the very slow velocities encountered in groundwater flow, Hubbert (1940) expressed this mathematically as:

$$\oint \left(\frac{\partial(gz)}{\partial s} + \frac{1}{\rho} \frac{\partial p}{\partial s} \right) ds \stackrel{!}{=} 0 \quad (2.7)$$

("!" in combination with "=" translates to "must equal")

and, since the gravity field is a potential field, this leads to:

$$\oint \left(\frac{1}{\rho} \frac{\partial p}{\partial s} \right) ds \stackrel{!}{=} 0 \quad (2.8)$$

To satisfy this condition, the fluid density has to be either constant or vary uniquely-dependent on pressure. For groundwater flow that complies with these conditions, and neglecting $v^2/2$, a fluid potential Φ exists, and combining Equations 2.1b and 2.8 leads to:

$$\Phi = g H_0 \quad (2.9)$$

This mathematically justifies rewriting Darcy's Law (Eq. 2.2) in terms of equivalent hydraulic heads H_0 (Eq. 2.4) as (Bachu, 1995b):

$$\bar{q} = -\frac{\mu_0}{\mu} K_{H_0} \left[\nabla H_0 + \frac{\Delta \rho}{\rho_0} \nabla z \right] - K_C \nabla C - K_T \nabla T \quad (2.10)$$

where K_{H_0} is the hydraulic conductivity for a reference fluid with ρ_0 and μ_0 .

Similarly to the considerations for the work along a closed path in the force field (Eq. 2.7), the fluid flux should only be dependent on the difference in fluid potential (or hydraulic head) between two points, and therefore should not be affected by the actual flow path between these two points. For the flux vector to be actually derived from a potential field, it has to be irrotational in a mathematical sense (Bachu, 1995b):

$$\begin{aligned} \nabla \times \bar{q} = & \underbrace{-\mu_0 \nabla \left(\frac{1}{\mu} \right) \times \left[K_{H_0} \left(\nabla H_0 + \frac{\rho - \rho_0}{\rho_0} \nabla z \right) \right]}_I - \underbrace{\frac{\mu_0}{\mu} \nabla K_{H_0} \times \left(\nabla H_0 + \frac{\rho - \rho_0}{\rho_0} \nabla z \right)}_{II} \\ & - \underbrace{\frac{\mu_0}{\mu} K_{H_0} \cdot \nabla \left(\frac{\rho - \rho_0}{\rho_0} \right) \times \nabla z}_{III} - \underbrace{\nabla K_T \times \nabla T}_{IV} - \underbrace{\nabla K_C \times \nabla C}_{V} \stackrel{!}{=} 0 \end{aligned} \quad (2.11)$$

For this equation to equal zero, every one of the five expressions (I - V) or a combination thereof has to be zero, with the following implications for each term (Bachu, 1995b): (I) $\mu = \text{const.}$ or $\nabla \mu$ parallel to ∇H_0 and ∇z ; and (II) $K_{H_0} = \text{const.}$ or ∇K_{H_0} parallel to ∇H_0 and ∇z ; and (III) $\rho = \text{const.}$ or $\nabla \rho$ parallel to ∇z ; and (IV) ∇K_T parallel ∇T ; and (V) ∇K_C parallel ∇C . Physically speaking, these conditions require that fluid density (ρ), viscosity (μ), temperature (T) and salinity (C), as well as rock permeability (k) and the phenomenological coefficients K_T and K_C , are either constant or vary with depth only (vertical stratification). Only when all these conditions are being simultaneously met the

flow is irrotational and derives from a potential, which allows the use of hydraulic heads for a correct representation of the flow field.

Due to the large size of sedimentary basins, the density and viscosity of the fluid, the permeability of the rock framework, and the temperature and concentration fields vary significantly in any direction (Hanor, 1994). Therefore, the restrictions for the properties of the fluids and the porous medium derived above show that, *sensu-stricto*, it is mathematically incorrect to use potentiometric surface maps of hydraulic heads for the representation, analysis and interpretation of the flow of formation water in sedimentary basins. Nevertheless, if coupled flow processes are neglected ($K_T, K_C \ll K_H$), Darcy's Law becomes:

$$q = -\frac{\mu_0}{\mu} K_{H_0} \left[\nabla H_0 + \frac{\Delta \rho}{\rho_0} \nabla z \right] \quad (2.12)$$

and assuming constant fluid properties ($\rho = \text{const.}, \mu = \text{const.}$) and isotropic permeability

$$q = -K_{H_0} \nabla H_0 \quad (2.13)$$

with flow along ∇H_0 (maximum slope on maps of hydraulic head distribution).

For this reason, contour maps of equivalent hydraulic heads are extensively used in hydrogeological studies, even for variable-density fluids and anisotropic permeability distributions, because they are often the only interpretative tools available (Bachu, 1995b). It remains to be investigated however, how sensitive Equation 2.12 is to variations in fluid density. It might be possible to define a range in which, although the density may vary, the rotational component in Equation 2.13 remains small enough so that hydraulic heads provide an adequate and meaningful representation of the fluid flow.

2.3 Methods for fluid flow representation and analysis

Pressure variation versus depth and elevation

Plots of pressure versus depth, $p(d)$, and pressure versus elevation, $p(z)$, are important tools to investigate fluid pressure – topography relations and fluid flow in general. The pressure in a static, continuous column of water in contact with the ground surface is:

$$P = \rho \cdot g \cdot d = \gamma \cdot d \quad (2.14)$$

with d = depth (m); γ = vertical pressure gradient (Pa/m).

Therefore, plotting pressure data versus depth allows characterizing the pressure conditions of subsurface fluids by comparing the measured fluid pressures to freshwater hydrostatic pressure. Deviations from freshwater hydrostatic pressure may be caused by: a) vertical flow in the aquifer (Fig. 2.1a), b) lack of hydraulic continuity with hydrostatically pressured aquifers and the ground surface (Fig. 2.1b and c); c) density variations, and d) fluid sinks or sources within the aquifer or bounding aquitards. A distinction can be made between “sub- and above-hydrostatic pressures” for pressures that are solely caused by topography, density variations and fluid flow, and “under- and overpressured”, for pressures that cannot be explained by the previous causes alone (Orr and Kreitler, 1985). These causes have to be identified before a proper characterization of the flow is possible.

The vertical component in Darcy's Law can be expressed as (Bachu 1995b):

$$q_z = -\frac{k}{\mu} \left(\frac{\partial p}{\partial z} + \rho g \right) \quad (2.15)$$

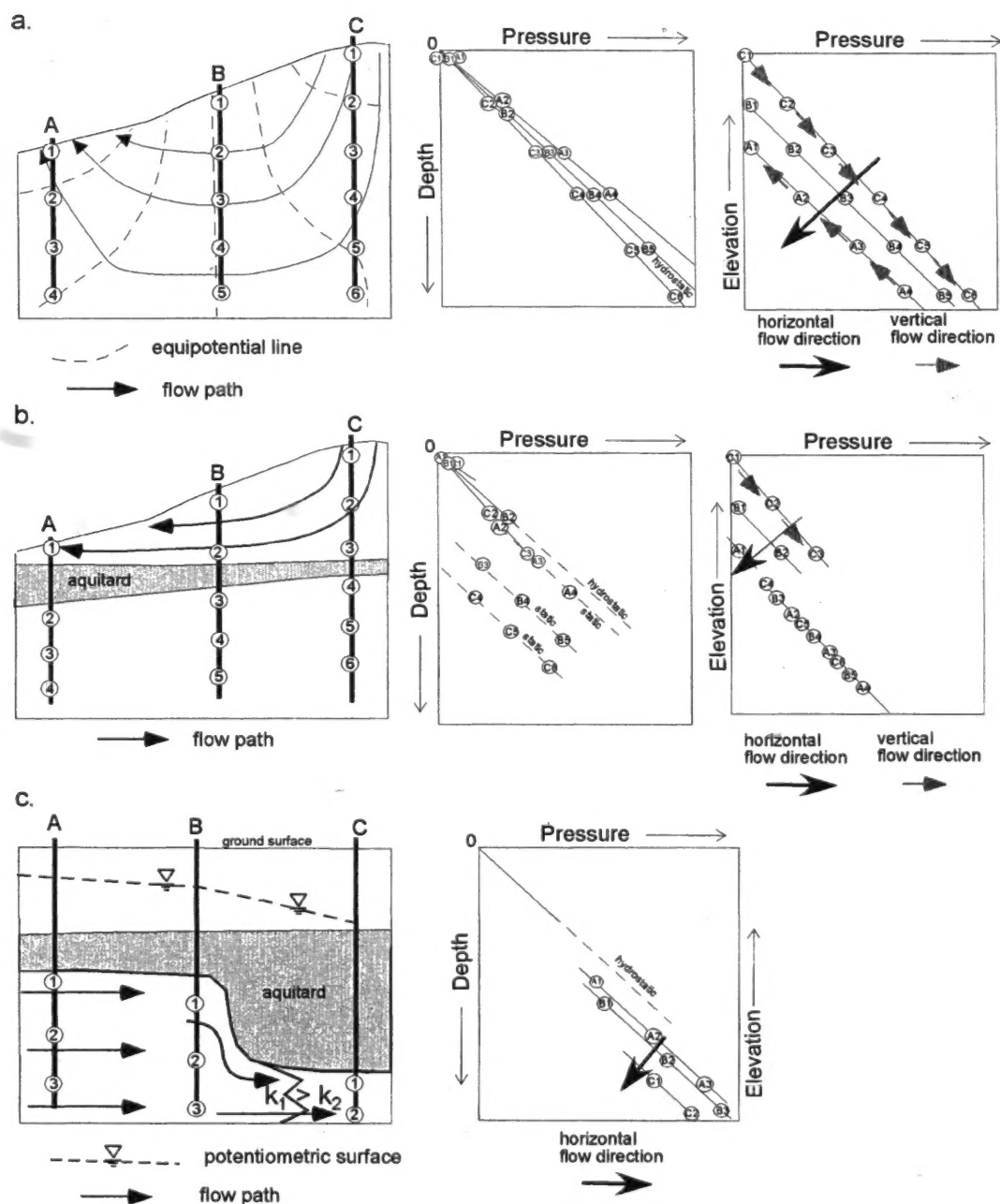


Figure 2.1: Schematic patterns of flow in the subsurface and respective distributions of fluid pressure versus depth and elevation: a) Topography-driven flow in a continuous, homogeneous aquifer; b) aquitard separating shallow, topography-driven flow system from deep aquifer with static flow conditions (after Tóth, 1978; Orr & Kreitler, 1985); c) horizontal flow in a thinning aquifer with decreasing permeability.

Hence, vertical flow directions can be determined by $\frac{\partial p}{\partial z} = \rho g$, $\frac{\partial p}{\partial z} > \rho g$ or $\frac{\partial p}{\partial z} < \rho g$, indicating no vertical flow, and upward or downward flow, respectively as shown in Figure 2.1a (upward flow in well A, no vertical flow in well B, and downward flow in well C). To calculate the actual fluid flux in the vertical direction, this method is valid only if the pressure measurements are from the same well or from an unconfined, homogeneous aquifer. For confined hydrogeological conditions, the potentiometric surface rarely follows the ground surface topography. Instead, the potentiometric surface lies above or below the ground surface, indicating above-hydrostatic or sub-hydrostatic pressure conditions in the subsurface, respectively, depending on the locations of the recharge and discharge areas.

If $\rho = \text{const.}$, then the vertical pressure gradient is constant, and the distribution of pressures versus depth plot along a straight line. Otherwise the pressure gradient varies with depth according to the vertical density variation. If the salinity increases significantly with depth, then this dominates the density distribution, as opposed to the density decrease due to elevated temperatures at depth (McCain, 1991). Pressure versus depth distributions for formation waters of various constant densities, and a non-constant increase in pressure for a gradual increase in density with depth are shown in Figure 2.2.

Generally, purely hydrostatic pressures are present only in an unconfined aquifer with no flow or strictly horizontal flow ($q_z = 0 \Rightarrow \frac{\partial p}{\partial z} = \rho g$, well B in Figure 2.1a).

Pressures in a confined aquifer with no horizontal flow that is connected to the ground surface at some lower elevation than the directly overlying ground elevation do not plot along a single straight line in a $p(d)$ -plot. Instead, the vertical pressure distributions in each well follow different straight lines, each with a static gradient, that do not extrapolate to zero pressure at zero depth (Fig. 2.1b); hence making it difficult to draw conclusions on the flow conditions.

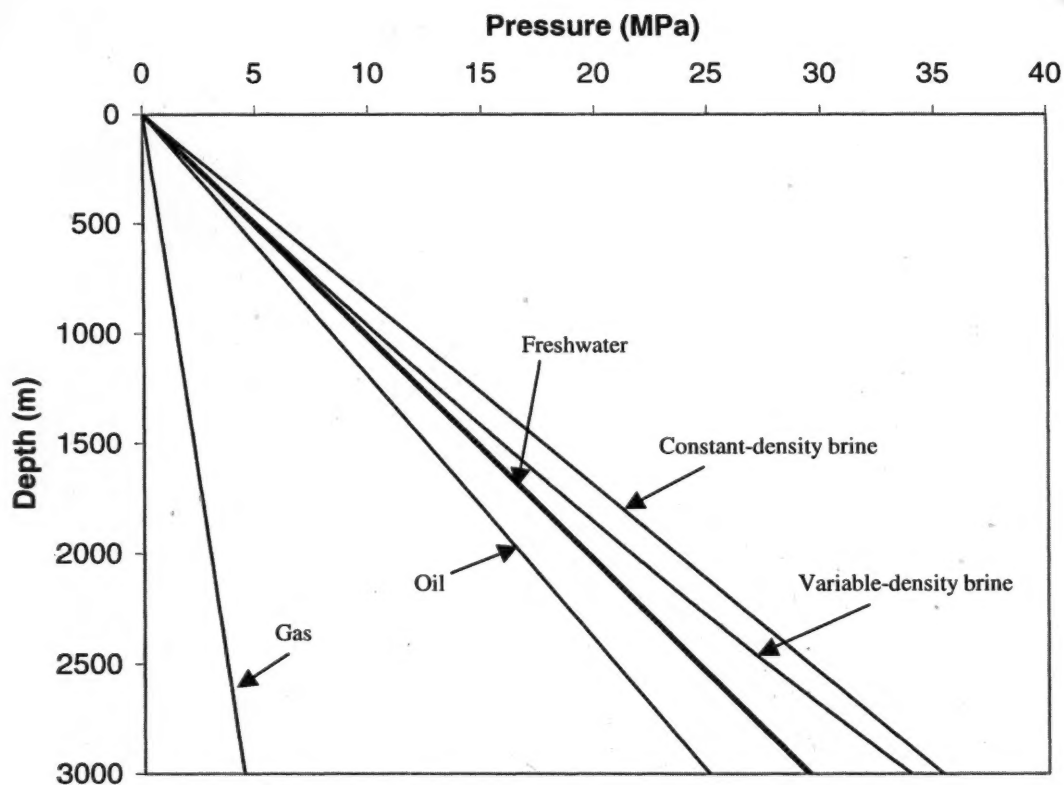


Figure 2.2: Static pressure distributions versus depth for various fluid densities: $\rho_{\text{Gas}} = 120 \text{ kg/m}^3$, $\rho_{\text{Oil}} = 850 \text{ kg/m}^3$, $\rho_{\text{Freshwater}} = 1000 \text{ kg/m}^3$, $\rho_{\text{Brine}} = 1200 \text{ kg/m}^3$. Starting with 1000 kg/m^3 , the density was increased by 5 kg/m^3 every 100 m ($\rho = 1150 \text{ kg/m}^3$ at 3000 m depth) to calculate the theoretical pressure distribution of a variable-density brine with linearly increasing density versus depth.

In contrast, the $p(z)$ -plots compare fluid pressure variations to a reference elevation (sea level). The pressure value at any point in the subsurface extrapolated along a hydrostatic gradient to pressure conditions at the ground surface ($p = 0$) indicates the hydraulic head with respect to the sea level as datum, which, in a conventional topography-driven flow system, is approximately equal to the ground surface elevation. For example, pressures measured in well B in Figure 2.1a plot along a straight line with a static water gradient that crosses the y-axis at the respective ground surface elevation for zero pressure in the $p(z)$ -plot. Pressures in wells A and B also plot lines with pressure gradients slightly higher and lower than hydrostatic, indicating upward and downward flow, respectively.

For the case of two separate aquifers in Figure 2.1b, all pressures in the confined aquifer lie on a straight line with a static gradient, correctly indicating no horizontal flow.

Pressure-elevation plots may be used also to assess the homogeneity of a specific aquifer. Consider horizontal flow of a constant-density fluid in an aquifer with homogeneous thickness and permeability distribution. Then in each well, pressures plot on a straight line with a static gradient (Fig. 2.1c; wells A and B), and the offset of each line is dependent on the constant hydraulic gradient between wells according to Darcy's Law (Eq. 2.13). If the permeability decreases along the flow path, the hydraulic conductivity term decreases accordingly:

$$K_{H_1} = \frac{k_1 \cdot \rho \cdot g}{\mu} > K_{H_2} = \frac{k_2 \cdot \rho \cdot g}{\mu} \quad \text{for } k_1 > k_2. \quad (2.16)$$

Thus, if there are no fluid sinks or sources within the aquifer, the horizontal flux q is constant, and the hydraulic gradient increases accordingly across the zone of permeability change.

Similarly, if the aquifer becomes thinner and the extent stays constant, the same amount of fluid must pass through a reduced area of the original aquifer; hence the hydraulic gradient has to increase according to (e.g., Freeze and Cherry, 1979):

$$Q = -K_H \cdot \nabla H_0 \cdot A \quad (2.17)$$

where, Q = flow rate (m^3/s), $A = a \cdot b$ = area of the aquifer (m^2), b = aquifer thickness (m), a = lateral extent of the aquifer perpendicular to the flow direction (m). The hydraulic conductivity multiplied by the aquifer thickness is defined as transmissivity T (e.g., Freeze and Cherry, 1979):

$$T = K_H \cdot b \quad (2.18)$$

In the example in Figure 2.1c, a decrease in permeability and/or transmissivity along the flow path results in an increase in hydraulic gradient between wells B and C, which is exemplified by an increase in the slope of the potentiometric surface and larger offset of lines through pressure measurements between wells B and C than between wells A and B, yet constant well spacing.

For regional-scale hydrogeological investigations, pressure-elevation plots generally seem to have more useful information on pressure conditions in the subsurface than pressure-depth plots. First, they always indicate the direction of flow and the approximate elevation of the potentiometric surface. Secondly, deeper, confined aquifers are at least partly disconnected by major aquitards from recharge from the directly overlying ground surface, so that the $p(d)$ -plot using the ground surface as datum will only indicate over- or underpressured conditions. In the pressure-depth analysis for individual aquifers in this study, a pressure gradient is used that represents the average water density in each aquifer.

Representation of variable-density fluid flow using hydraulic heads and driving force vectors

Typically, lateral fluid flow is interpreted by using 'freshwater hydraulic head' distributions. Flow is inferred to be from high to low hydraulic heads, and freshwater hydraulic heads H_f are calculated using the density of freshwater at standard conditions ($\rho_f = 1000 \text{ kg/m}^3$) as reference density in Equation 2.4. To be able to distinguish in this study between the general definition of hydraulic heads, in which any density may be used as reference density and the special case of freshwater hydraulic heads, subscripts "0" and "f" refer to a general and freshwater density, respectively.

With x , y , z representing the principal axes of anisotropy, and horizontal permeability components k_x , k_y and vertical permeability component k_z , Darcy's Law can be decomposed into its horizontal (q_x , q_y) and vertical (q_z) components (de Marsily, 1986, p. 64):

$$\begin{aligned}
 q_x &= -\frac{k_x \cdot \rho \cdot g}{\mu} \cdot \frac{\partial H_0}{\partial x}, & q_y &= -\frac{k_y \cdot \rho \cdot g}{\mu} \cdot \frac{\partial H_0}{\partial y}, \\
 q_z &= -\frac{k_z \cdot \rho \cdot g}{\mu} \left(\frac{\partial H_0}{\partial z} + \frac{\rho - \rho_0}{\rho_0} \right)
 \end{aligned} \tag{2.19}$$

Hence, using only hydraulic heads results in a correct interpretation of flow in the horizontal plane. On the other hand, if the flow has a vertical component, as in the case of sloping aquifers, the representation of flow using only hydraulic heads introduces errors, because the density term in the q_z component is neglected.

Even if the density is constant but different from freshwater, errors result from the use of freshwater hydraulic heads as shown in the following theoretical example (Jorgensen et al. 1982). In Figure 2.3 static conditions and a constant brine density, higher than freshwater, are assumed. The ground surface coincides with the sea level elevation, so that plots of fluid pressure versus depth and pressure versus elevation are identical. Freshwater hydraulic heads can be calculated for the two test locations in the aquifer:

$$H_{f1} = z_1 + \frac{p_1}{\rho_f g} \quad ; \quad H_{f2} = z_2 + \frac{p_2}{\rho_f g}$$

As can be seen from the extrapolation in the $p(z)$ - plot (Fig. 2.3), these head values are not the same, $H_{f2} > H_{f1}$, implying flow from left to right, which obviously is wrong because there is no flow in the aquifer (hydrostatic conditions assumed a priori). If the actual water density is used as a reference density instead of freshwater, then $H_1 = H_2$ and the system correctly shows no flow.

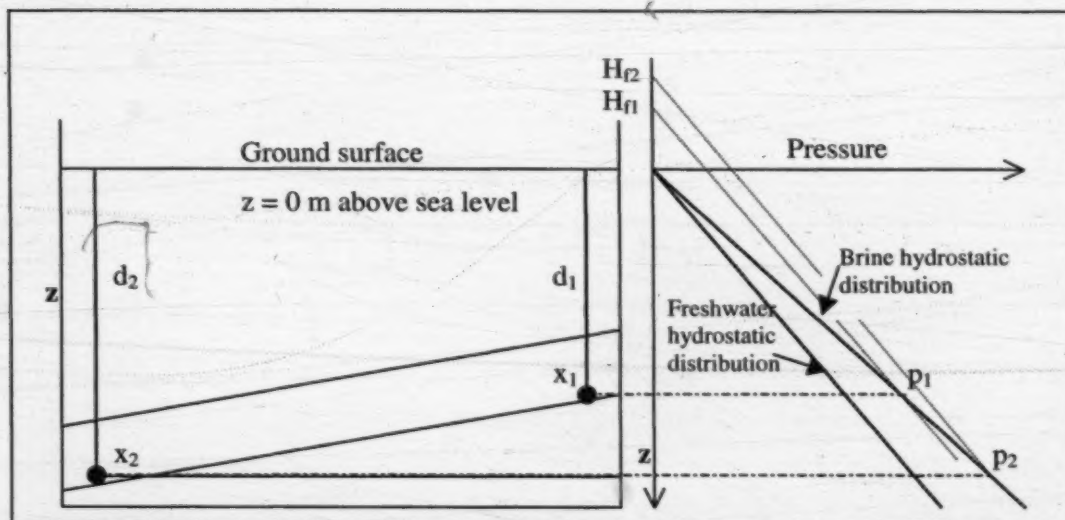


Figure 2.3: Cross sectional view of an aquifer saturated with a constant-density brine and penetrated by two wells aligned along the z -axis, and corresponding pressure-elevation plot (z = elevation, d = depth, x = location of pressure measurement, p = pressure).

This result can be extended to the case of a static system containing variable-density water. The assumption of static conditions can be mathematically expressed by setting the fluid flux $q = 0$ (Eq. 2.12):

$$q = -\frac{k \rho_0 g}{\mu} \cdot \left(\nabla H_0 + \frac{\rho - \rho_0}{\rho_0} \nabla z \right) = 0 \quad (2.20)$$

$$\Rightarrow \nabla H_0 = -\frac{(\rho - \rho_0)}{\rho_0} \nabla z$$

Only if the actual fluid density is used as reference density in Equation 2.20, the gradient becomes 0, and Darcy's Law correctly shows no flow. Thus, using freshwater hydraulic heads calculated from pressure data measured at different elevations introduces an error

into the interpretation of fluid flow that is represented by the term $-\frac{(\rho - \rho_0)}{\rho_0} \cdot \nabla z$ that,

in the case presented above, wrongly indicates flow. Generally, this term could be considered as an 'artificial' buoyancy term that is always introduced when choosing a reference fluid density other than the actual fluid density.

On the other hand, using the actual fluid density ρ in a variable-density system at every point where the hydraulic head is calculated also results in a wrong interpretation of the flow direction, as illustrated again in the case of a static system (Fig. 2.4). The variable-density head can be expressed as:

$$H_v = \frac{p}{\rho g} + z \quad (2.21)$$

where ρ is the actual fluid density and, if ρ is not constant, then H_v is a function of p , z and ρ , as opposed to H_0 , which is only a function of p and z .

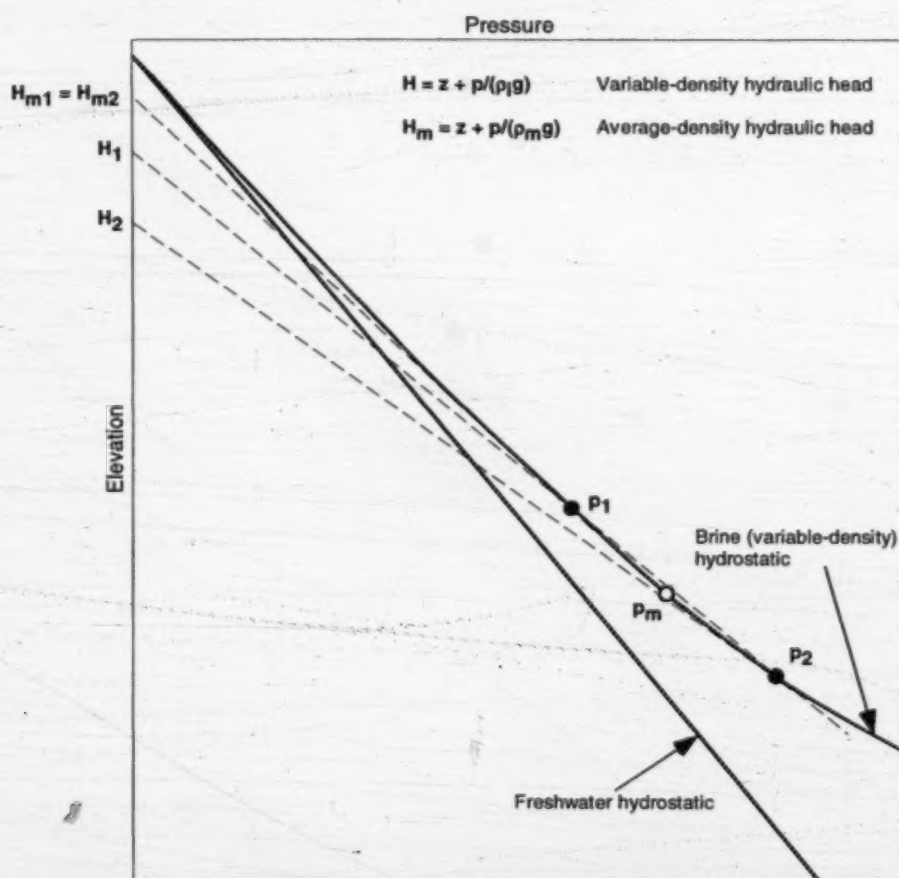


Figure 2.4: Pressure-elevation plot for static conditions in an aquifer containing variable-density formation water (linear density increase with depth), schematically showing differences in hydraulic head calculations for various densities. For the spatial relationship between p_1 and p_2 see cross section in Figure 2.3.

There is a difference in variable-density heads ΔH_v between points x_1 and x_2 , and flow down-slope is implied from right to left, although static conditions are assumed a priori. Nevertheless, for any linear density variation with depth, a correct result and flow interpretation would be achieved by using an average density $\rho_m = (\rho_2 + \rho_1)/2$ in the hydraulic head calculation, which, in this case results in $H_{m1} = H_{m2}$, correctly indicating no flow.

Gupta and Bair (1997) modeled steady-state, variable-density fluid flow using a numerical code based on Equation 2.12 (Kuiper, 1983). They compared calculated fluid flux vectors and variable-density heads in the Mt. Simon Sandstone aquifer, which showed implicitly that the actual flow direction and magnitude do not correspond to the variable-density head gradient, hence that variable-density heads wrongly represent fluid flow. Mathematically, this can be shown by substituting the expression for the variable-density head (Eq. 2.16) into Equation 2.13:

$$\begin{aligned} -K \nabla H_v &= -K \left(\frac{\nabla p}{\rho g} + \nabla z - \frac{p}{\rho^2 g} \nabla \rho \right) = -\frac{k}{\mu} \left(\nabla p + \rho g \nabla z - \frac{p}{\rho} \nabla \rho \right) \\ &= q + \frac{k p}{\mu \rho} \nabla \rho \end{aligned} \quad (2.22)$$

which adds a term to, and therefore contravenes, Darcy's Law.

In order to consider any density variation with depth, Luszczynski (1961) introduced the concept of "environmental hydraulic heads", H_e , which he defined as:

$$H_e = H_f + \frac{\rho_f - \rho_a}{\rho_f} \cdot (z_g - z) \quad (2.23)$$

where z_g = ground surface elevation, ρ_f = freshwater density, H_f = freshwater hydraulic head, and ρ_a = average fluid density, defined as:

$$\rho_a = \frac{1}{z_g - z} \int_z^{z_g} \rho dz \quad (2.24)$$

The environmental hydraulic head considers the hydrostatic pressure within a column of variable-density water connected to the ground surface, and would correctly describe the hydrostatic pressure distribution in Figure 2.4 for a hydraulically continuous aquifer system. Environmental hydraulic heads correctly indicate the vertical flow component, but misrepresent the horizontal components of fluid flow, because, similar to variable-density heads, they contravene Darcy's Law when introduced in Equation 2.12 (Bachu, 1995b). In addition, they are difficult to calculate for natural settings, even if only the vertical flow component is sought, because the exact density distribution is usually not known and the pressure distribution in the aquifers is not necessarily vertically continuous to the ground surface, if they are confined by intervening aquitards.

It is instructive to split the driving force acting on the fluid into its pressure-related and density-related force components. From Darcy's Law, the total driving force F^* per unit volume acting on the fluid can be expressed as (Hubbert, 1940; Bachu 1995b):

$$F^* = -\rho_0 \cdot g \left(\nabla H_0 + \frac{\rho - \rho_0}{\rho_0} \cdot \nabla z \right) = \frac{\mu}{k} \bar{q} \quad (2.25)$$

The driving force only indicates the potential for fluid flow, but it does not identify the acting driving mechanism(s).

In sloping aquifers flow is along the confining layers. Kuiper (1983) developed a numerical model for simulating flow in these aquifers by decomposing the flow rate into two orthogonal components in the bedding plane and a vertical component. Similarly, for the two-dimensional case of a sloping aquifer at the angle Θ (Fig. 2.5a), the flow driving force per unit volume along the aquifer slope is (Dorgarten and Tsang, 1991):

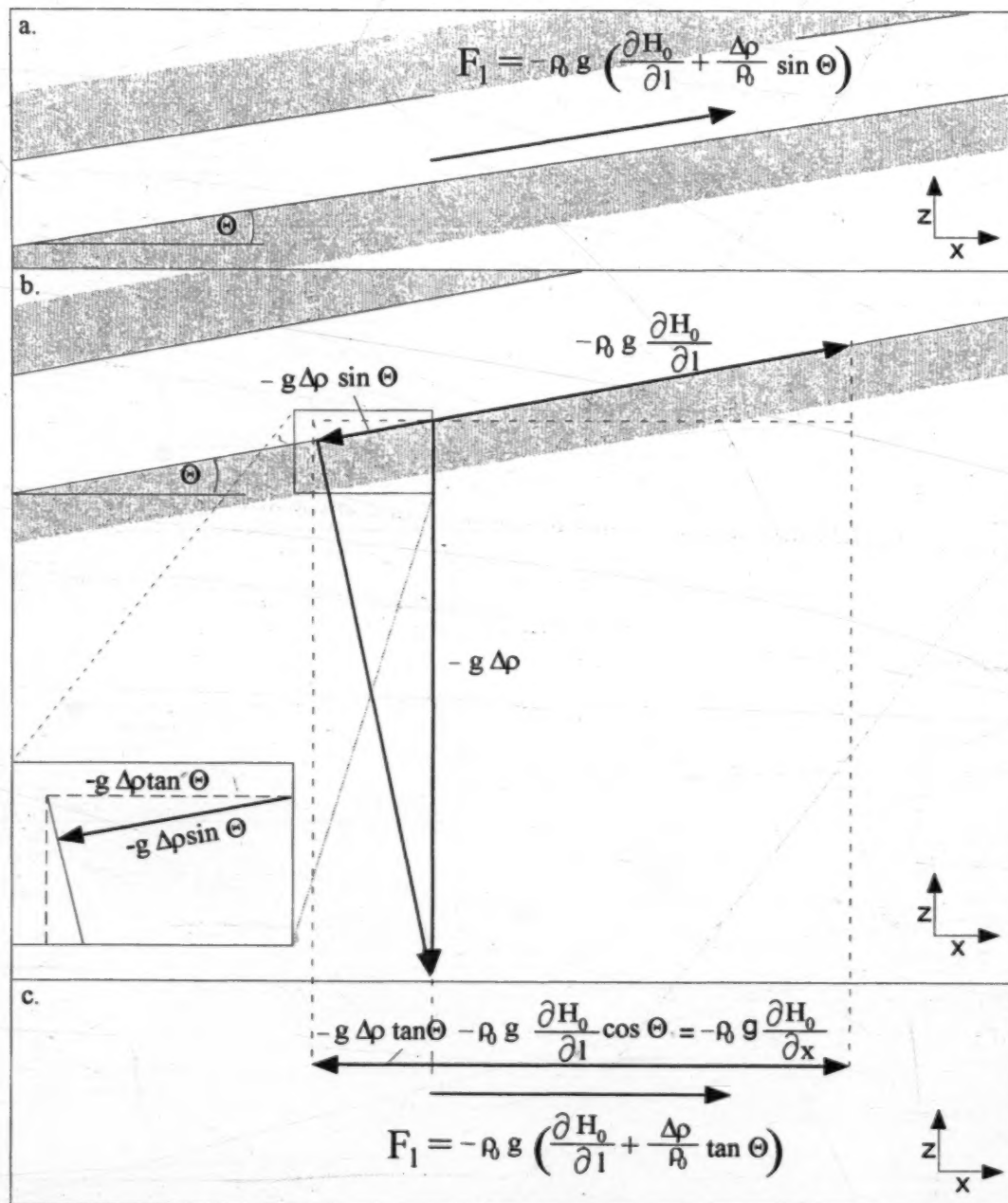


Figure 2.5: Diagram of the two-dimensional decomposition of the driving force vector along a sloping aquifer and the approximation of its components in Cartesian coordinates (H decreases along the x -axis): a) total driving force along the aquifer slope ($\tan \Theta = \nabla E$), b) pressure- and density related force components, c) horizontal driving force and its components.

$$F_l = -\rho_0 g \left(\frac{\partial H_0}{\partial l} + \frac{\Delta \rho}{\rho_0} \sin \Theta \right) \quad (2.26)$$

Short of numerical modeling, and because $\frac{\partial H_0}{\partial l}$ and $\sin \Theta$ are difficult to evaluate, this force is decomposed in Figure 2.5 into its horizontal (x) and vertical (z) components (Cartesian coordinates). If the angle Θ of the aquifer slope, defined as ∇E , is small, then:

$$\frac{\Delta \rho}{\rho_0} \sin \Theta \cong \frac{\Delta \rho}{\rho_0} \tan \Theta \quad \text{and} \quad \frac{\partial H_0}{\partial l} \cong \frac{\partial H_0}{\partial x}, \quad \text{so that}$$

$$F_l \cong -\rho_0 g \left(\frac{\partial H_0}{\partial x} + \frac{\rho - \rho_0}{\rho_0} \tan \Theta \right) \quad (2.27)$$

is a good approximation for the driving force acting on the fluid along the confining layers of a dipping aquifer. For three dimensions Equation 2.27 becomes:

$$F_l \cong -\rho_0 g \left(\nabla_{xy} H_0 + \frac{\rho - \rho_0}{\rho_0} \nabla E \right) \quad (2.28)$$

where ∇_{xy} = gradient in the horizontal plane only (x and y components).

When solely using equivalent hydraulic heads (H_0), only the pressure-related force component of the total fluid driving force is being considered, which results in the prediction of a wrong flow direction (by the angle ψ) and erroneous flow magnitude (Fig. 2.6).

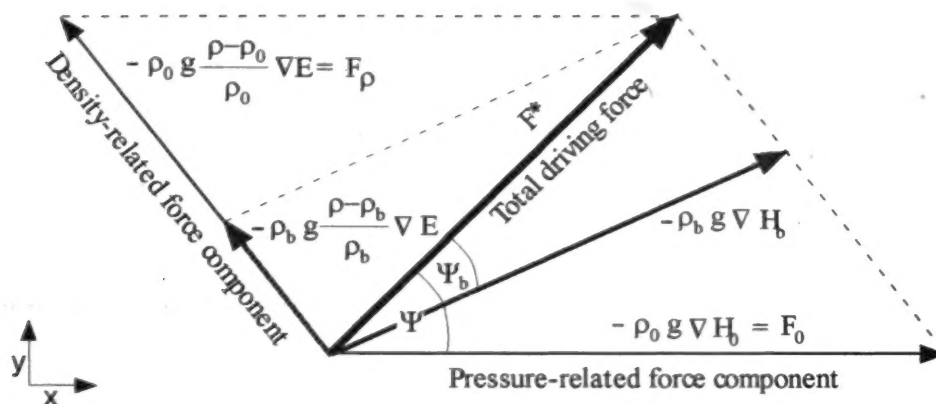


Figure 2.6: Vector diagram of driving force components in plan view for various reference densities (modified after Davies, 1987).

The schematic vector diagram (Fig. 2.6) shows that basically any value may be chosen for the reference density, which results in an infinite number of combinations into which the driving force vector can be decomposed. Thus, the “buoyancy” term in Darcy’s law (Eq. 2.12) and in the driving force vector equation (Eq. 2.25) corrects for errors that are introduced by using a reference density different from the actual formation water density in the representation of a variable-density fluid system.

According to Equation 2.25, the following parameters are needed to describe fluid flow using driving force vectors: a) pressure, b) measurement elevation, and c) fluid density. In addition, permeability and fluid viscosity are needed for the calculation of fluid fluxes (see following section). In plan view, the driving force vector method represents the lateral driving force acting on the fluid in an aquifer. When constructing driving force vectors, only the hydraulic head and elevation are introduced spatially by the differentiation of their values, thus considering the hydraulic gradient between adjacent points of possibly different elevation. On the other hand, the density values are introduced only at the point under consideration and are individually compared to a reference value but not to each other. Thus, the relative buoyancy of adjacent points is not actually taken into account.

Although mathematically more accurate, the construction of driving force vector maps still requires considerably more work than the calculation and mapping of hydraulic heads. Also, the aquifer slope has to be averaged over a certain distance, and the fluid density at the points for which the driving force is determined is calculated from contour maps of salinity and subsurface temperature. This introduces technical and averaging errors in addition to the ones that already exist for the pressure data used in the calculation of hydraulic heads (see Chapter 3).

Therefore, the validity and applicability of hydraulic head interpretations compared to the driving force is examined more closely. Davies (1987) defined the driving force ratio (DFR) as the ratio of the pressure- and density-related components of the driving force:

$$DFR = \frac{\rho - \rho_0}{\rho_0} \cdot \frac{|\nabla E|}{|\nabla_{xy} H_0|} \quad (2.29)$$

Based on numerical simulations that actually calculated the flux vector q in a homogeneous and isotropic aquifer, Davies (1987) suggested a value $DFR = 0.5$ as a threshold above which the distribution of freshwater hydraulic heads gradient alone does not sufficiently represent lateral flow in the aquifer, and density variations have to be explicitly accounted for. He also pointed out that this threshold value might vary depending on the scale and the required accuracy of a particular study. A $DFR = 0.5$ infers a difference of up to 50 % in magnitude between the actual driving force and its pressure-related component, and a deviation from the actual flow direction of up to 30° . The maximum difference in magnitude and direction cannot occur simultaneously. The maximum of the magnitude error occurs for zero deviation ($\psi = 0$), whereas the maximum deviation occurs for a minimum of the magnitude error. The relationship between force components and total force on the fluid is shown in Figure 2.7.

$$\sin \Psi_{\max} = \frac{\rho - \rho_0}{\rho_0} \cdot \frac{|\nabla E|}{|\nabla H_0|} \text{ for } DFR \leq 1 \quad (2.30)$$

and $\Psi_{\max} = 180^\circ$ for $DFR > 1$, which is also the maximum possible deviation max ($\Psi_{\max}$).

It is helpful to examine both the DFR and the orientation of the pressure- to the density-related force components in order to identify whether the prediction of the magnitude and/or the direction of the driving force are significantly in error. When using freshwater density as the reference density, the density-related component of the driving force is directed downdip for water densities $> 1000 \text{ kg/m}^3$, which is the case for most sedimentary basins with high-salinity formation water. There are various extreme cases to be considered:

- (a) The pressure-related force component is directed downdip, along the aquifer slope. In this case, using only the pressure component underestimates the magnitude of the driving force, but it does not misrepresent its direction. Hence, by using only equivalent freshwater hydraulic heads, the magnitude of the driving force will always be underestimated, but the predicted flow direction is correct.
- (b) The pressure-related force component is directed updip, again parallel to the aquifer slope. By using only freshwater hydraulic heads for $DFR < 1$, the magnitude of the driving force is overestimated. For $DFR > 1$ the flow direction is actually opposite (downdip) to the updip one indicated by the pressure component.
- (c) If a different density than that of freshwater is chosen as a reference state, the direction of the density-related force component is directed updip for actual densities smaller than the reference density, and downdip for actual densities larger than the reference density. The equivalent hydraulic gradient is opposed (updip or downdip) to the driving force vector only in the cases of $DFR > 1$ and opposed density- and pressure-related force components.

In cases a) – c) the DFR is equal to the percentage of error in the magnitude between the equivalent hydraulic gradient and the actual total force acting on the fluid.

The previous examples represent special flow conditions, whereas in the general case the aquifer slope and the pressure-related force component are at an angle. A DFR = 1 is still the threshold above which there is the possibility that the flow direction, as inferred from the gradient of equivalent hydraulic heads, is reversed, or opposed to the actual flow direction.

As explained earlier, any value may be chosen as reference density ρ_0 , but, for the same flow conditions, different reference densities result in different DFRs. Therefore, it should be possible to find a suitable reference density for which the DFR is minimal and hydraulic heads alone are sufficiently accurate to represent flow. Figure 2.8 illustrates how, under the same flow conditions ($F^* = \text{const.}$) in a variable-density system, different reference densities and the direction of the density-related component affect the difference between the driving force and its pressure-related component. It considers cross-sectional (2-D) flow along a sloping aquifer ($\nabla E = \text{const.}$), for various values for the reference density ρ_0 and a fluid density range 1000–1200 kg/m³ commonly observed in sedimentary basins. The value on the y-axis compares the total driving force F^* to its pressure-related component F_0 :

$$\frac{F^*}{F_0} = \frac{\left| -\rho_0 g \left(\nabla H_0 + \frac{\Delta\rho}{\rho_0} \nabla E \right) \right|}{\left| -\rho_0 g \nabla H_0 \right|} = 1 \pm \text{DFR} \quad (2.31)$$

depending on whether $\Delta\rho > 0$ or $\Delta\rho < 0$.

Regardless of the flow direction, the ratio F^*/F_0 is given by $1 - \text{DFR}$ for flow opposite to its density-related component, and by $1 + \text{DFR}$ for flow where the two are in the same direction. Thus the flow magnitude is over- or underestimated, respectively, when using hydraulic heads only in the flow representation, depending on the relative position of the driving force and its density-related component.

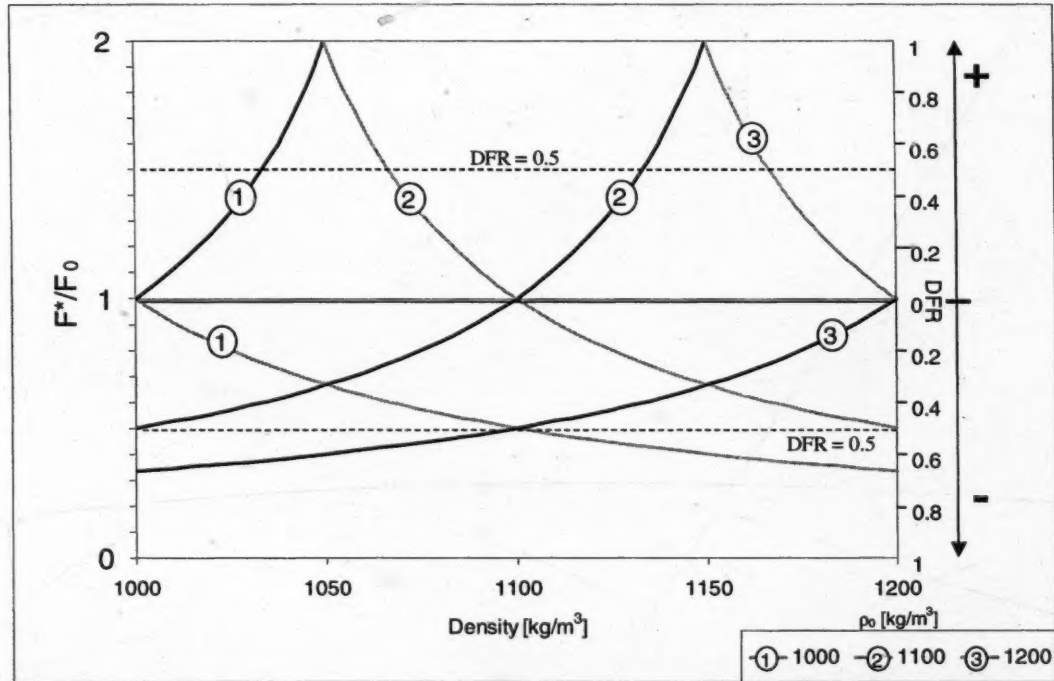


Figure 2.8: Graph showing the error introduced when interpreting the driving force as derived from equivalent hydraulic head gradients only, versus the driving force (for 2-D flow along the slope of the aquifer; +/- indicate over- or underestimation of the actual driving force acting on the fluid, respectively). The grey and black curves represent updip flow and downdip flow, respectively. F^*/F_0 was calculated according to Equation 2.31 for $\nabla E = 0.01$ and $\nabla H_0 = \frac{F^*}{\rho_0 \cdot g} - \frac{\rho - \rho_0}{\rho_0} \nabla E$, where the constancy of the arbitrarily chosen flow driving force is expressed by $\frac{F^*}{g} = 1 \frac{m^3}{kg}$.

As expected, $DFR \approx 0$ and $F^*/F_0 = 1$ if the fluid density ρ is constant and the reference density is chosen as $\rho_0 = \rho$, which means that the distribution of equivalent hydraulic heads accurately describes the lateral flow in the aquifer. In the case of a variable density distribution, for any reference density ρ_0 and predefined critical DFR value (DFR_{crit}), the density range $\rho_{min} - \rho_{max}$ for which $DFR < DFR_{crit}$ is constant, but asymmetrically distributed around ρ_0 , depending on the flow direction. Therefore, choosing a reference density at the lower or upper end of the naturally observed density range in sedimentary

basins limits the use of hydraulic heads alone, because parts of the theoretically available density range are practically ignored. For example, arbitrarily choosing a $DFR_{crit} = 0.5$ in a system where ρ ranges between 1000 and 1200 kg/m^3 , shows that using the average density as reference density ($\rho_0 = 1100 \text{ kg/m}^3$) allows for the widest range of fluid density variation, within which flow can still be satisfactorily interpreted with equivalent hydraulic heads (Tab. 2.1).

$\rho_0 \text{ (kg/m}^3\text{)}$	Flow direction	$\rho_{min} \text{ (kg/m}^3\text{)}$	$\rho_{max} \text{ (kg/m}^3\text{)}$
1000	Updip	1000 (970)	1100
	Downdip	1000 (900)	1030
1100	Updip	1070	1200
	Downdip	1000	1130
1200	Updip	1170	1200 (1300)
	Downdip	1100	1200 (1230)

Table 2.1: Example of minimum and maximum density values from Figure 2.8 for which $DFR < 0.5$. The numbers in brackets refer to the theoretically minimum and maximum density values, which are not commonly observed in sedimentary basins.

Because formation water densities significantly below 1000 kg/m^3 or above 1200 kg/m^3 usually do not occur in sedimentary basins, the allowable density range for freshwater ($\rho_f = 1000 \text{ kg/m}^3$) or high-saline brine (1200 kg/m^3) as reference density is smaller. When examining the flow of high-density brines, the DFR values, hence the errors introduced by using only hydraulic-head distributions, are minimized, if an appropriate reference density that reflects the average brine density is chosen. This allows for a better application of equivalent hydraulic heads and for a wider density range, while the use of equivalent freshwater hydraulic heads would actually maximize the error.

When a theoretically accurate representation and analysis is required for a flow domain with varying fluid density, it is necessary to calculate driving force vectors to account for effects of density variation. Nevertheless, one should be aware of the practical errors in this procedure. As shown earlier, the driving force is unique at every point in the aquifer

and it can be decomposed in an infinite number of pressure- and density-related components by choosing different values for ρ_0 . Therefore, at least theoretically, adding the pressure-related force components, derived from hydraulic head distributions, to the density-related force components should result in the same, unique force vector field, independent from the reference density. It should be emphasized that "unique" does not automatically imply that it is the "correct" driving force, because the accuracy of the force vectors still depends to a large extent on the original data quality used in its calculation. Practically, when calculating the force field on a regular grid from irregularly distributed data (hydraulic heads, formation water density, aquifer slope) the force vector field is not necessarily unique, because the gridding process introduces errors due to the inter-, and extrapolation of data points. The effect of data accuracy on the representation of flow will be discussed further in Chapter 3.

In some cases, especially in regional-scale hydrogeological studies, it might be less important to know the exact flow direction and magnitude, and the use of equivalent hydraulic heads gives satisfactory results for the interpretation of the general flow field. Calculating the DFR at critical points in the study area helps in determining the potential error of this analysis. Depending on the required accuracy for the particular study, a threshold value for the DFR has to be chosen above which the errors in the equivalent hydraulic head interpretation become unacceptable. This threshold value can basically range between $DFR = 0$ (exact solution) and $DFR = 1$ (possibility of opposed flow and 100 % error in force magnitude). By predefining an acceptable error in the deviation of the flow direction, and/or its magnitude, the threshold DFR value can be calculated either directly from Equation 2.29, or using Table 2.2.

Max. Error in Force Magnitude [%]	Max. Deviation [°]	DFR
0	0.0	0
10	5.7	0.1
20	11.5	0.2
30	17.5	0.3
40	22.6	0.4
50	30.0	0.5
60	36.9	0.6
70	44.4	0.7
80	52.1	0.8
90	64.2	0.9
100	90.0	1
< 100	180	< 1

Table 2.2: Driving force ratio (DFR) as a function of maximum errors of force magnitude and direction resulting from the interpretation of equivalent hydraulic heads without accounting for density variations.

Permeability Distribution and Fluid Flux

The distributions of driving forces and/or hydraulic heads are indicative only of the potential for fluid flow and of the flow direction. The actual flow rate is given by Darcy's Law (Eq. 2.12), that can be also written as:

$$\bar{q} = \frac{k}{\mu} \cdot F^* \quad (2.32)$$

Equation 2.29 shows that the flow is largely controlled by the permeability of the porous medium, because k varies within several orders of magnitude (e.g., Freeze and Cherry, 1979, p. 29), while μ changes usually by less than one order of magnitude (de Marsily, 1986).

In a homogenous aquifer, F^* correctly indicates the flow direction (if known and calculated correctly). The driving force F^* calculated based on $\nabla_{xy} H_0$ and $\frac{\Delta\rho}{\rho_0} \nabla E$ is still good for indicating the flow direction (first approximation), while $\nabla_{xy} H_0$ alone (second approximation) is acceptable only if the DFR value is below a predetermined critical value. The flow magnitude is still not known unless multiplied by a constant k and divided by a constant μ . The same holds for a heterogeneous aquifer, only that F^* has to be multiplied by the respective k/μ , depending on its distribution in the aquifer. In an anisotropic aquifer even the directions of driving force and flux vector are different from each other and delineating flow paths becomes very difficult without knowledge of the permeability distribution and anisotropy characteristics.

2.4 Illustrative example of optimizing the reference density in the hydraulic-head calculation

For illustration, the effect of selecting different reference densities in the calculation of hydraulic heads is presented in the following for the flow representation in a part of the Elk Point aquifer in the study area. This aquifer is a good example, because, besides the slope of the aquifer, it contains high-salinity formation water and low hydraulic gradients so that the water density and the reference density used in the calculation of hydraulic heads have a significant effect on the flow representation. An $80 \times 130 \text{ km}^2$ area defined by $116 - 118^\circ \text{ W}$ and $54.25 - 55.0^\circ \text{ N}$ was chosen because of the data distribution and the erosional limit of the Elk Point Group. The top of the Elk Point aquifer varies from -1270 m in the southwest to -1680 in the northeast, with an average slope of 10.9 m/km (Fig. 2.9). The density of the formation water, calculated on the basis of salinity and the average geothermal gradient (Bachu and Burwash, 1991, 1994), increases north-northwestward from approximately 1090 to 1135 kg/m^3 (Fig. 2.10). Figures 2.11 – 2.14 show the distributions of hydraulic heads and of the Driving Force Ratios (DFR), which were calculated with the following reference densities: $\rho_f = 1000 \text{ kg/m}^3$ (freshwater), $\rho_{\min} = 1090 \text{ kg/m}^3$, $\rho_{\max} = 1135 \text{ kg/m}^3$, and $\rho_{\text{av}} = 1120 \text{ kg/m}^3$ (field average). The flow-driving force field is superimposed on each hydraulic-head map to illustrate the errors made by inferring flow on the basis of hydraulic heads only and by neglecting the density-related force component. If hydraulic heads correctly represent the flow direction, the force vectors should be perpendicular to the hydraulic head contour lines, and the DFR ideally should be zero, but definitely significantly smaller than 1.

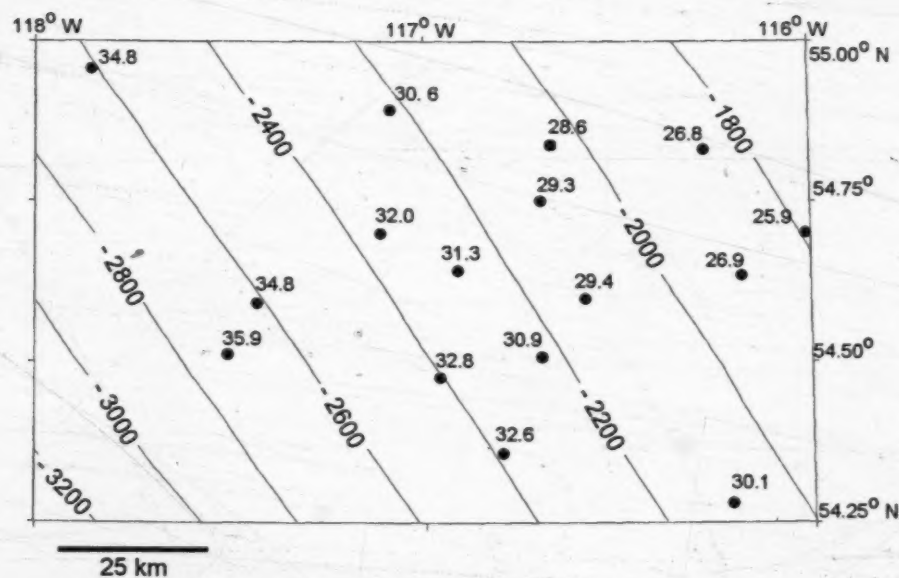


Figure 2.9: Structure top of the Elk Point aquifer (m.a.s.l.) and observed formation water pressures (MPa) at the top of the aquifer.

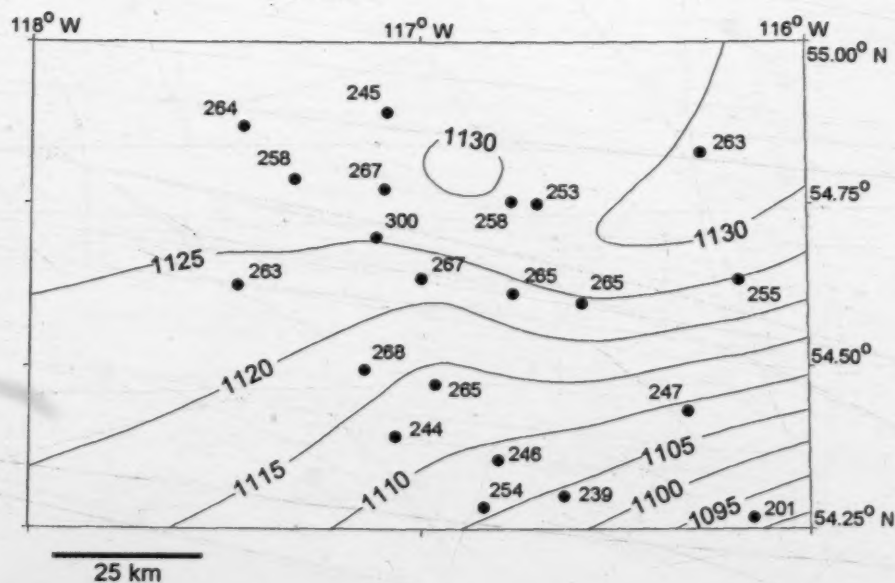


Figure 2.10: Density distribution (kg/m^3) and salinity values (g/l) of formation water in the Elk Point aquifer.

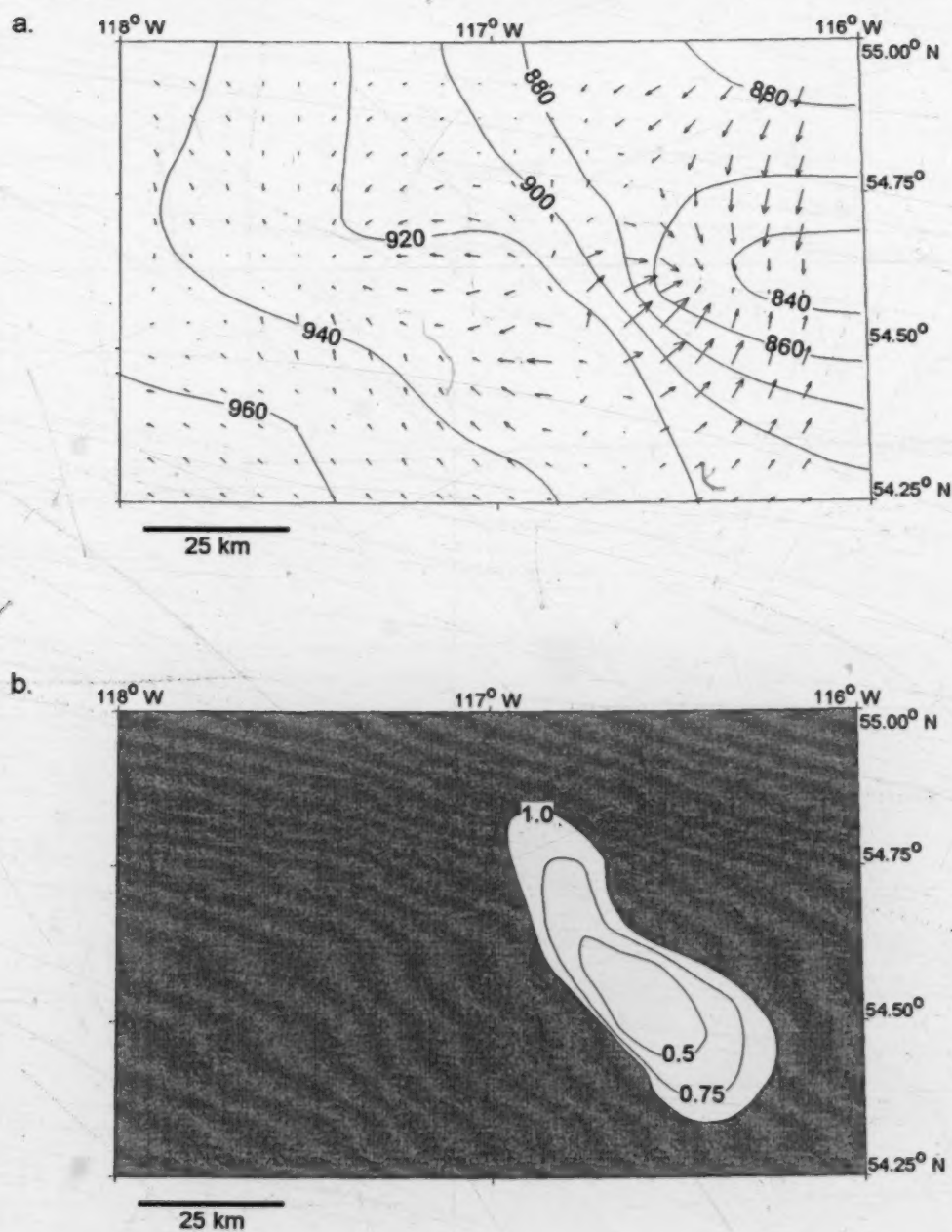


Figure 2.11: Flow representation in the Elk Point aquifer using $\rho_0 = 1000 \text{ kg/m}^3$ as reference density: a) Freshwater hydraulic head distribution (m) overlain by driving force vector field, b) DFR distribution, area where DFR > 1 is shaded in grey.

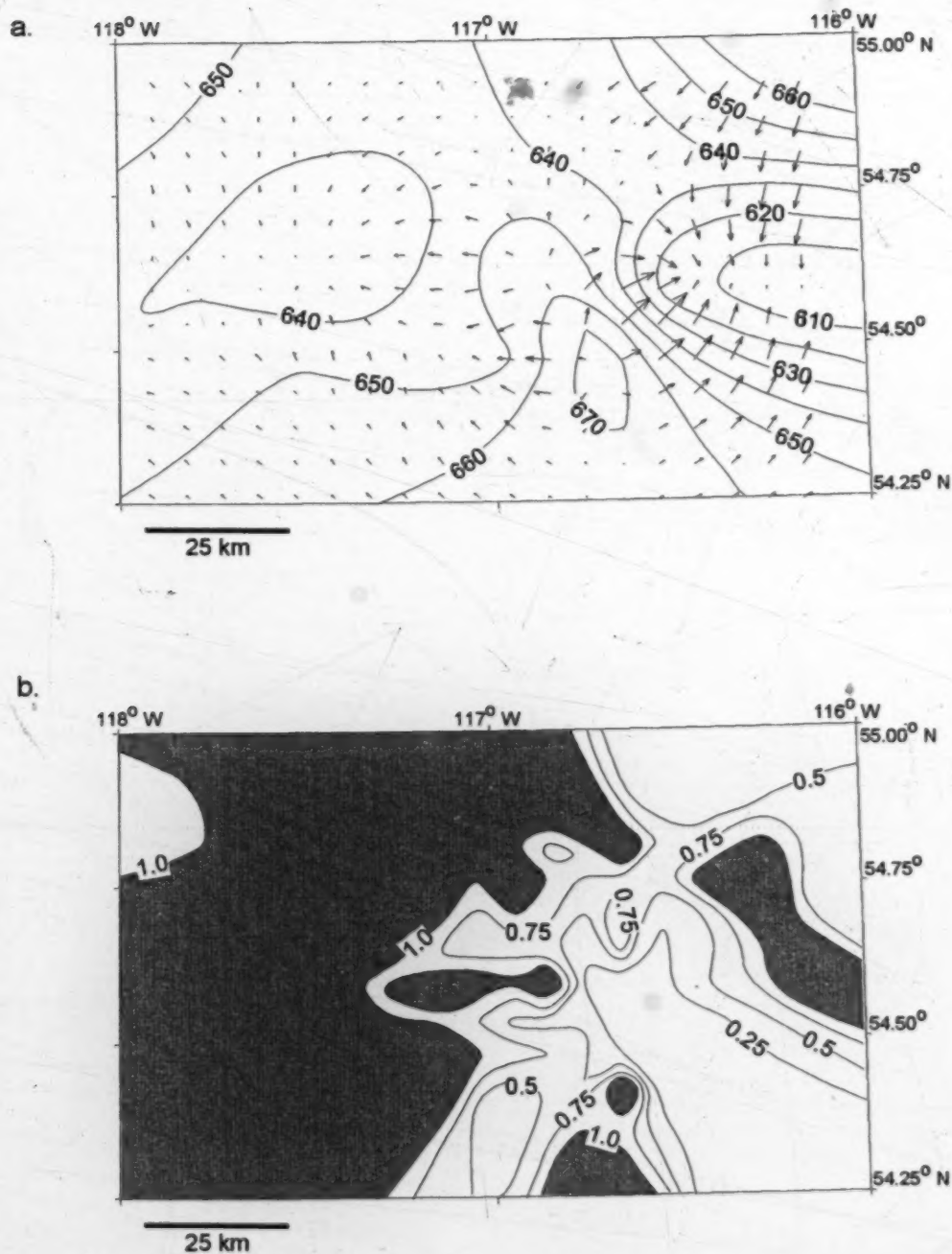


Figure 2.12: Flow representation in the Elk Point aquifer using $\rho_{\min} = 1090 \text{ kg/m}^3$ as reference density: a) Hydraulic head distribution (m) overlain by driving force vector field, b) DFR distribution, area where DFR > 1 is shaded in grey.

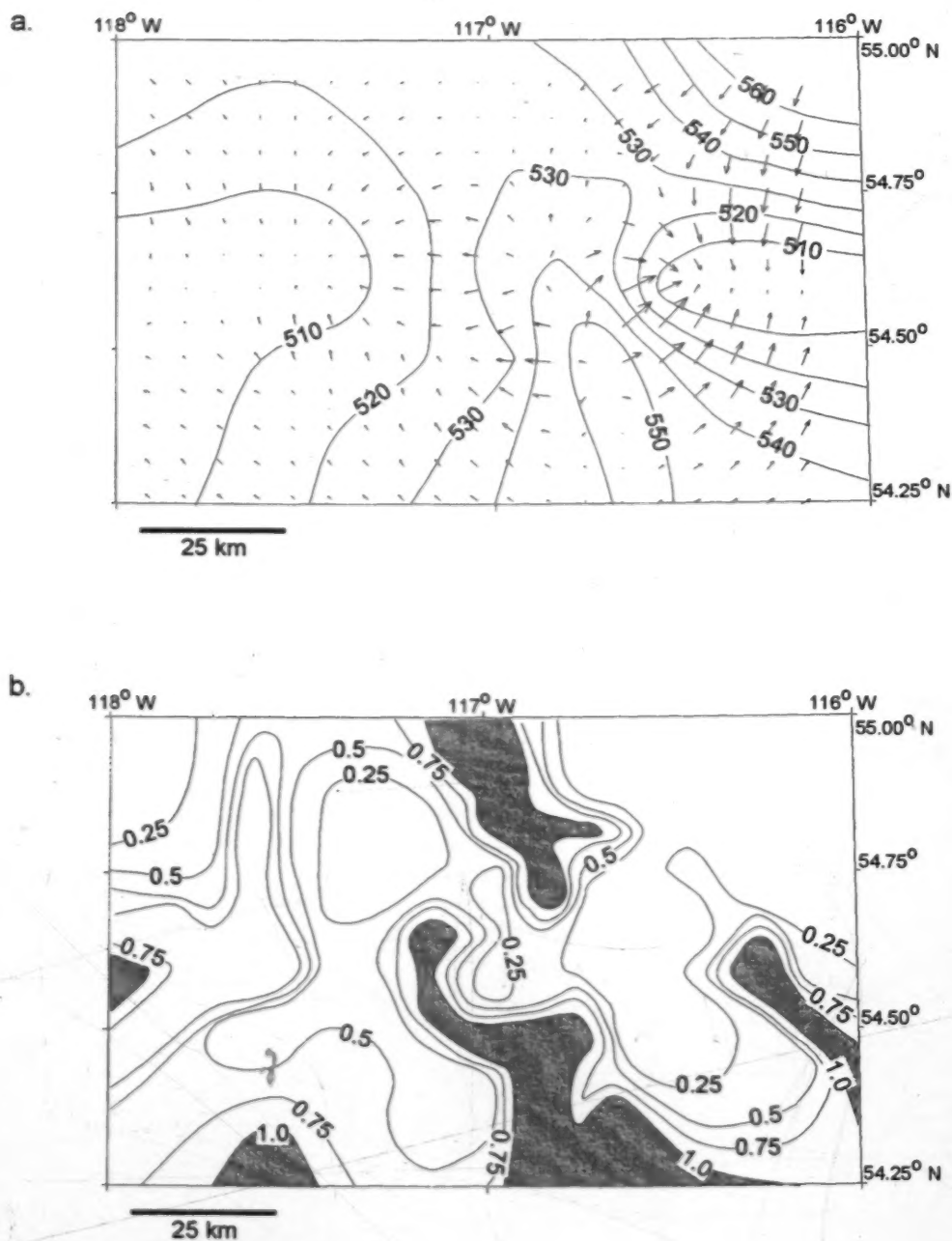


Figure 2.13: Flow representation in the Elk Point aquifer using $\rho_{\max} = 1135 \text{ kg/m}^3$ as reference density: a) Hydraulic head distribution (m) overlain by driving force vector field, b) DFR distribution, area where DFR > 1 is shaded in grey.

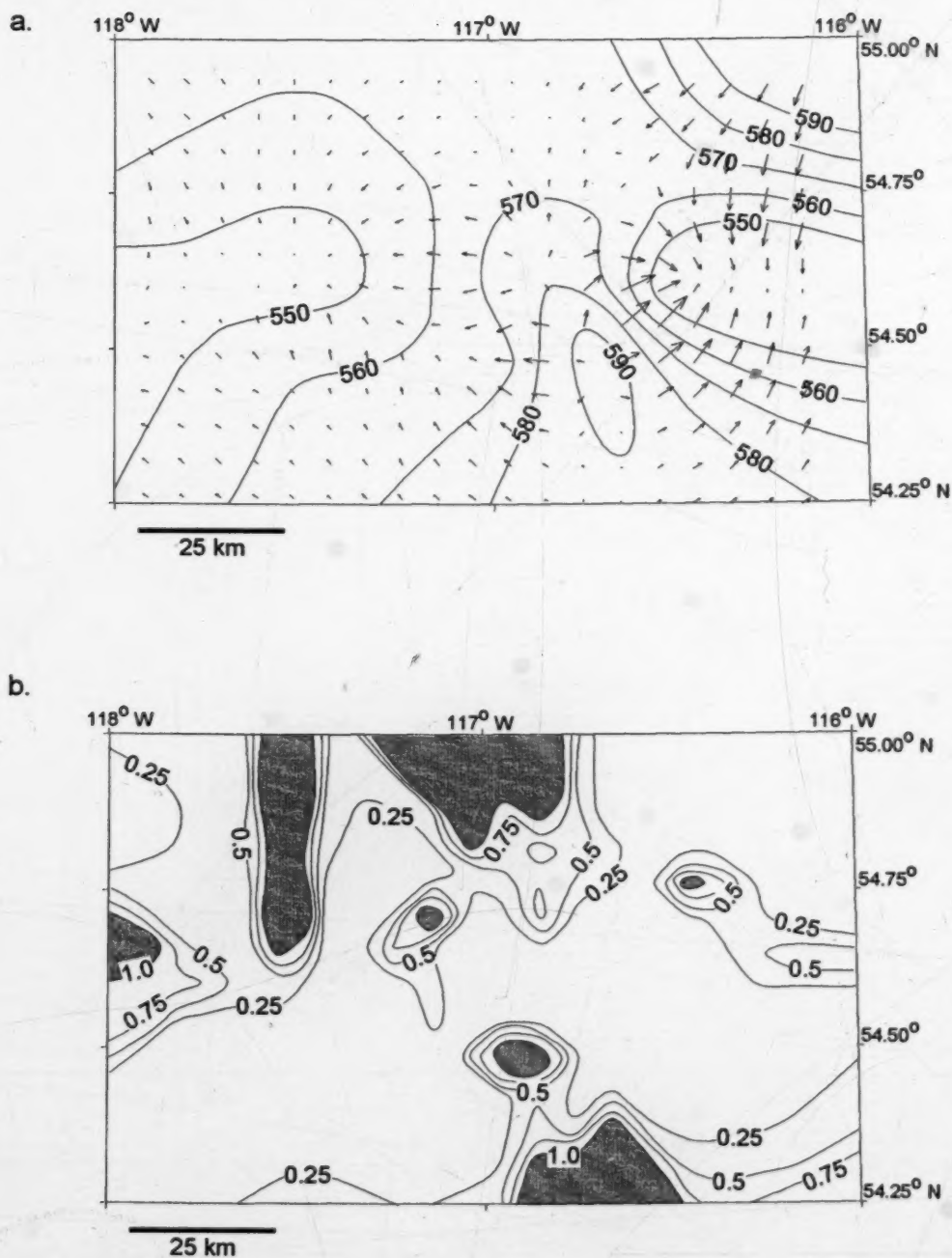


Figure 2.14: Flow representation in the Elk Point aquifer using $\rho_{av} = 1120 \text{ kg/m}^3$ as reference density: a) Hydraulic head distribution (m) overlain by driving force vector field, b) DFR distribution, area where DFR > 1 is shaded in grey.

Freshwater hydraulic heads generally decrease from above 940 m in the south and in the west to less than 840 m in the east, suggesting north- and eastward directions of formation water flow (Fig. 2.11 a). On the other hand, the force vectors indicate westward flow in the western two thirds of the study area and eastward flow in the eastern third. This shows that only in the east, where the hydraulic gradient is relatively steep, flow directions inferred from freshwater hydraulic heads are more or less comparable to the force vectors. In the remainder of the study area the hydraulic head contours are mainly parallel (in the SW) or even opposite (in the N) to the force vectors, hence significantly misinterpreting the direction of formation water flow. The respective DFR values are larger than 1 for most parts of the study area, with an areal average of 4.5 (Fig. 2.11 b), showing that hydraulic heads calculated with a freshwater reference density are not appropriate to represent flow in this part of the Elk Point aquifer.

Hydraulic heads calculated with $\rho_o = \rho_{min}$ vary in the 610 - 670 m range (Fig. 2.12 a) and correctly predict the flow direction and strength in the eastern third of the study area. The flow in the western two thirds is better represented than for the freshwater reference density case, although errors in direction are still present, particularly in the W-NW. This is consistent with the DFR distribution (Fig. 2.12 b), where the $DFR < 1$ in most of the eastern third of the study area, and > 1 in the western two thirds. The areal DFR average of 2.3 is overall lower than in the case for $\rho_o = \rho_f$. The inferred flow radiates from a local hydraulic-head high of 670 m in the southeast, and converges toward the 610 m low in the east and the low (< 640 m) in the west (Fig. 2.12 a).

Hydraulic heads calculated with $\rho_o = \rho_{max}$ vary in the 510 to 560 m range (Fig. 2.13 a) and correctly predict the flow direction and strength over most of the study area. In the southwest, hydraulic heads suggest flow from a tongue of high hydraulic heads, as opposed to the radiating flow pattern indicated by the flow-driving force, while in the west flow is toward a < 510 m low, west of the 510 m contour line. The DFR values are generally lower than in the case of $\rho_o = \rho_{min}$ (Fig. 2.13 b), with an areal average of 1.2. The regions where the flow is still incorrectly depicted by hydraulic-head distributions, particularly in terms of local direction, correspond to a $DFR > 1$.

Finally, hydraulic heads calculated with the field density average $\rho_o = \rho_{av}$, which vary in the 550-590 m range, seem to be most appropriate to infer flow direction and strength (Fig. 2.14 a), correctly showing, beside the strong features, the radiating flow from the hydraulic-head high in the southwest, and the flow towards the < 550 m low west of the 550 m contour line. The DFR values are generally the lowest of all cases presented, with an areal average of 0.6 (Fig. 2.14 b).

The previous example shows that, when using only hydraulic heads in the representation of variable-density fluid flow in sloping aquifers, choosing a reference density value within the observed range of formation water densities helps to minimize the errors in the flow interpretation caused by the neglect of the density-related force component. It is difficult to define an optimal reference density, because the DFR depends on the actual density variation, the reference density and the ratio between aquifer slope and hydraulic gradient. Nevertheless, in cases with a more or less constant hydraulic gradient and a relatively constant aquifer slope the field average of the observed fluid densities is probably the best choice for the reference density. On the other hand, using the freshwater density in the calculation of hydraulic heads maximizes the DFR, hence the error in the flow interpretation, because in almost all cases it lies at the lower end or outside the spectrum of formation water densities in the aquifers to be investigated.

2.5 Summary and conclusions

Flow in sedimentary basins is driven by a combination of various mechanisms, such as a) topography (gravity), b) sediment compaction, c) tectonic loading, d) erosional rebound, e) buoyancy, f) overpressures due to hydrocarbon generation, g) osmosis and h) mineral phase changes. The internal and boundary conditions for fluid flow change with time and various driving mechanisms may be active during different stages of the basin history. Pressure dissipation and fluid flow as a result of the various flow-driving mechanisms are transient processes, and their rates largely depend on the permeability distribution. Aquitards and lateral low-permeability barriers retard these processes so that the present-day pressures in the subsurface have not necessarily equilibrated to the present-day

internal and boundary conditions. Flow systems at shallow depth usually have adjusted to the current ground surface relief and are topography-driven, while flow in deeper, low-permeability environments, which are relatively isolated from the ground surface, may be controlled by other driving mechanisms or reflect a paleo-flow regime. In regional-scale hydrogeological studies, the effect of osmosis is usually negligible and the flow can be represented and analyzed by the driving force acting on the fluid, which combines all fluid driving mechanisms introduced by the diffusion equation.

Numerical modeling is the only tool to represent the transient flow and the interaction between various flow-driving mechanisms in a sedimentary basin, but modeling requires a large amount of data input and knowledge of the distribution of many variables in space and in time. The time needed for data collection, data availability and quality, and computational limits largely restrict the applicability of numerical models in the representation of flow in sedimentary basins to theoretical and conceptual studies.

The calculation of driving forces requires data of present-day distributions of pressure and fluid densities, and values for the aquifer slope; thus, a quasi-steady-state flow regime has to be inferred in any hydrodynamic analysis that uses this method. Driving force vectors deliver the theoretically most accurate solution for the magnitude and direction of current fluid flow based on actual data distributions, but their implementation is still relatively cumbersome, because three different data sets (∇H_0 , ρ , ∇E) are needed and have to be combined to calculate the driving force. Practically, this increases the potential sources for inaccuracies due to errors in the various data sets. Determining the fluid fluxes is even more complicated, because this requires the knowledge of the fluid properties (ρ , μ) and the permeability distributions, which are usually insufficiently known.

A less complicated method to represent and analyze flow is to use only the distribution of equivalent hydraulic heads (H_0). The driving force can be decomposed into its pressure-

and density related components, which are represented by the equivalent hydraulic-head gradient (∇H_0) and $\frac{(\rho - \rho_0)}{\rho_0} \nabla E$, respectively. The magnitude of each of these components varies, depending on the value of the reference density (ρ_0), while their vectorial sum (the driving force) is constant. Hence, when using driving force vectors, any density value may be chosen as reference density. The use of equivalent hydraulic heads in variable-density fluid flow is only valid for strictly horizontal flow. In sloping aquifers, the use of hydraulic heads alone introduces an error because the effects of density variation on the flow are neglected. The significance of this error can be evaluated by the DFR, which is defined as the ratio of the pressure- and density-related components of the total driving force. It has been demonstrated theoretically and with an example from the study area that choosing the average water density in the aquifer as the reference density minimizes the DFR to such an extent that the density-related force component may become negligible. The advantages and disadvantages of using driving force vectors versus hydraulic heads for the representation of flow in the study area are discussed further in Chapter 3, in which theoretical and practical aspects of both methods will be compared.

Constructing a hydrostratigraphic framework, by subdividing the sedimentary succession into various units, is intended to generate a framework in which the concept of using hydraulic heads and driving force vectors can be applied. Strict assumptions that have to be made for each hydrostratigraphic unit in order to be able to correctly apply these concepts, but that can be rarely realized, are: horizontal layering, a homogeneous, isotropic permeability distribution and a homogeneous fluid. When loosening these restrictions, flow directions are not necessarily perpendicular to contours of hydraulic heads or in the direction of the driving force vectors, and the interpretation of fluid flow is limited to a more qualitative analysis of hydrogeological data. It still has to be determined how large the error of the obtained solution is, and if the solution is, at least in general, representative of the actual fluid flow system. The margin for the change in aquifer slope and fluid density variations in relation to the hydraulic gradient can be determined by the DFR.

CHAPTER 3: DATA SOURCES AND PROCESSING

This chapter describes the sources and the processing of the various hydrogeological data that were used in this study. Also, data accuracy is discussed, especially with respect to how it affects the reliability of the hydrogeological interpretation methods.

3.1 Data sources

More than 150,000 wells have been drilled in the Alberta Basin by the petroleum industry, of which approximately 11,000 wells are located in the study area. By provincial law, all well data have to be submitted to the Alberta Energy and Utilities Board (EUB) and become part of the public domain after one year. For this study, stratigraphic picks of formation tops from the EUB well database and from data sets assembled for the Atlas of the Western Canada Sedimentary Basin (Mossop and Shetsen, 1994) were used to establish the geological and hydrostratigraphic framework. The hydrogeological data consist of pressure data from drillstem tests (DSTs) and hydrogeochemical analyses of formation waters. All of these data were collected by the petroleum industry in Alberta and were captured in electronic form in databases at the Alberta Geological Survey (AGS). No personal sampling or testing was performed.

3.2 Data culling

The EUB databases consist mainly of unprocessed data that contain errors due to: a) mechanical problems of testing methods and analyzing techniques, b) external influences on tests, such as production influence from surrounding wells, c) human error in sampling, analyzing techniques, and data interpretation, and d) human error in recording and electronic data entry. Therefore, the original data sets had to be culled for erroneous data before they were used in (hydro-)geological interpretations. The three main data sets: a) stratigraphic picks, b) pressure data, and c) formation water analyses, are affected by different error sources, and the culling procedure for each individual set is therefore presented separately.

Stratigraphic picks of geological formation tops

The depth of geological formation tops usually are assigned by a geologist during and after the drilling of a well, on the basis of drill cuttings, cores, and geophysical logs. The main errors introduced during this process are: a) report of a wrong ground surface elevation or kelly bushing (KB) for the well, b) a wrong stratigraphic pick based on personal judgment, c) wrong unit conversions (i.e., from ft to m), or d) erroneous electronic data entry.

Where available, the data used for the Geological Atlas of the Western Canada Sedimentary Basin (Mossop and Shetsen, 1994), stored at the AGS, were considered to be reliable, because the contributing authors of this volume had already individually checked and validated them. The remaining data were culled through an iterative process of gridding and mapping, i.e., checking the respective grids and maps for inconsistencies, and correcting single data points. The results were compared to existing structural maps, in the Geological Atlas of the Western Canada Sedimentary Basin (Mossop and Shetsen, 1994), for which one well per township, where available, was used for mapping. Depending on the data density for the respective stratigraphic units, between 31 and 355 stratigraphic picks of the Atlas set are in the present study area, which consists of approximately 380 townships. The gridding resolution of the Atlas maps (25 km increments) is lower than that of the maps in this study (12.5 km increments), in which a much larger number of stratigraphic picks was used (see Chapter 4, Tab. 4.1). Hence, when the newly created maps of this study matched the Atlas maps, differences of the order of metres were deemed acceptable, and the culling process was ended. Correcting and culling of single data points was either achieved by checking the original well logs, or by simply removing the well from the data set for areas where sufficient data exist and/or where the cause of error could not be determined.

Formation water analyses

The hydrochemical analyses in the AGS database were already culled prior to this study using the procedures described in Hitchon and Brulotte (1994). In this "automatic" culling process, analyses are sequentially rejected on criteria such as: incomplete analysis, drilling mud contamination, poor chemical analysis, sampling and production method, and fluid recovery. In addition, the analyses were culled manually based on the regional hydrogeochemistry (Table 3.1).

Flag #	Culling Criteria
1	Any of Ca, Mg, Cl, HCO ₃ (or alkalinity), or SO ₄ missing
2	Mg-concentration > Ca-concentration
3	10.0 < pH < 5.0
4	OH reported
5	CO ₃ reported
6	Calculated Na-concentration < 0
7	Density < 1000 kg/m ³
8	$([\text{cation}] - [\text{anion}]) / ([\text{cation}] + [\text{anion}]) > 0.15$
9	No sample depth interval reported
10	Method of production from excluded class
11	Sampling point from excluded category
12	Analysis from multiple drillstem tests
13	Only fluids which are dominantly non-aqueous recovered
14	DST recovered fluids where the water dominated fluid is < 10% of the total recovery
15	KCl mud contamination, $[\text{K}] / [\text{Na}] * 1000 > \text{threshold for individual formation}$
16	Culled manually by hydrogeochemist (e.g., Duplicate chemistry, values out of range for individual formation in given area, analytical problems...)

Tab. 3.1: Culling criteria for formation water analyses used in the automatic culling procedure (from Hitchon and Brulotte 1994).

These rejection criteria act on the data set in successive order of their individual importance. Herein, incomplete analyses for example are considered of the highest culling priority, because important ion concentrations are missing and these analyses cannot be hydrochemically balanced. This will affect mainly analyses where only one component (most often chloride) is reported. Drilling and production methods are considered of a lesser priority, because they might suggest a high possibility of sample contamination due to their technical nature, but the quantitative influence on the analysis cannot be defined. In the AGS database there are 9593 water chemistry analyses for the entire stratigraphic succession in the study area performed up to 1992, of which only 1100 (11%) passed the mechanical culling criteria. This set was augmented by another 267 analyses performed since 1992, and acquired from the GeofluidsTM database licensed by Rakhit Petroleum Consulting Ltd. Distribution maps of total dissolved solids (TDS) and bicarbonate (HCO_3^-) concentrations were used in a unit-by-unit analysis. Examination of the anomalies that could not be reasonably explained by natural processes led to their rejection. The final number of formation water analyses used in the hydrogeological interpretations is shown in Table 3.2. Chemical analyses of gas and oil were not used in this study.

In many standard industry chemical analyses only the concentrations of the major ions (e.g., Cl^- , SO_4^{2-} , HCO_3^- , CO_3^{2-} , Mg^{2+} , and Ca^{2+}) are measured, and Na^+ is calculated by charge balance. The amount of total dissolved solids is calculated based on the calculated Na^+ and the remainder of the major ions. These calculations do not account for the K^+ concentrations in the formation waters, which in the study area generally are less than 10 % of the Na^+ concentrations, and therefore only introduce a small error in the TDS calculation. However, when interpreting formation water origin based on Na^+ concentrations these errors might become significant. Therefore, a subset of chemical analyses containing measured values for Na^+ and K^+ was used for the plotting of various ion relations in the formation waters. For these analyses the N^+ concentration was recalculated incorporating K^+ in the charge balance, to at least partly account for the relatively large analytical errors associated with Na^+ .

Formation	Chemistry # after cull	Original DST #	DST # after cull	A & B Quality	C Quality
Paskapoo / Coalspur	1	10	10	8	2
Brazeau	51	143	100	54	46
Cardium	40	131	80	34	46
Dunvegan	14	88	49	18	31
Viking	64	264	144	75	69
U. Mannville	35	198	89	56	33
L. Mannville	193	473	131	131	-
Total post-Jurassic	398	1307	603	376	227
Nordegg	11	41	22	15	7
Triassic	102	325	153	86	67
Permian (Belloy)	45	86	49	22	27
Carboniferous	140	293	167	90	77
Total Miss.-Jurassic	298	745	391	213	178
Wabamun	25	74	36	17	19
Winterburn	46	113	54	22	32
Woodbend	145	167	52	15	37
Beaverhill Lake	66	159	45	15	30
Elk Point	37	42	18	7	11
Cambrian	6	12	3	0	3
Total Cambr.-Devon.	325	567	208	76	132
Total	1021	2619	1202	665	537

Table 3.2: Distribution of valid formation water analyses and drill stem tests by hydrostratigraphic unit in the study area. Only DSTs of high quality (A, B and C) were used, except for the Lower Mannville, where only A and B quality tests were considered.

Pressure data

It is important for hydrogeological studies to use only good-quality pressure data. Therefore, only data that are derived from well-performed and interpreted DSTs, and from which stable formation pressures were calculated, should be used. Due to the mechanical complexity of the drillstem test procedure, there are many potential sources for error (Bredehoeft, 1965; Timmerman and van Poolen, 1972). The initial pressure data from a DST are transient pressures that are recorded during the test as the formation pressure recovers (pressure-"build-up" phase), and have to be converted into the stable formation pressures. Assuming radial flow in a homogenous medium to the well bore, the

solution of pressure recovery over time has a logarithmic form that ideally produces a straight line in semi-logarithmic coordinates (Horner-Method). By extrapolating the straight line to the origin (infinite time), the formation pressure is estimated (e.g., Dahlberg, 1995).

The pressure data available from the AGS database are extrapolated to the formation pressure from sources specialized in DST interpretations, such as the Canadian Institute of Formation Evaluation (CIFE), Digitech, or Hydro-Fax Resources Ltd. These companies assign an overall quality rating to each test, which describes the quality of the test, and, implicitly, a degree of reliability of the pressure value (Tab. 3.3). The fluid recovery is also reported.

'A'	best quality
'B'	nearing stabilization
'C'	caution (plugging)
'D'	questionable
'E'	low permeability, low pressure
'F'	low permeability, high pressure
'G'	misrun (flow only)

Table 3.3: Standard-industry data quality classes for DSTs.

Drill stem test data of quality A and B (665) were used preferably in the hydrogeological interpretation (Tab. 3.2). Due to increasing data scarcity towards the deeper parts of the basin, C quality data (537) were added to most of the units, but these data were checked for their accuracy by examining the individual drill reports and build-up curves, and by removing non-reliable tests. This led to the rejection of 54 % of the DST data, leaving 1202 DSTs from an original number of 2619 (Tab. 3.2).

In addition to the testing problems, in the study of the natural flow regime in the basin it has to be ensured that the measured pressures are not influenced by production-induced

drawdown (PID) from adjacent wells. Production from the same aquifer and contained reservoirs leads locally to lower pressures than the undisturbed, "virgin" formation pressure, whereas injection of fluids increases formation pressures. The PID depends on: the distance r between tested and pumped wells, time t since the start of pumping, production rates Q , hydraulic conductivity K and specific storage S_s (deMarsily, 1986). The magnitude of drawdown s expressed in terms of drop in hydraulic head caused by production in a well, as a function of radial distance from the DST well and the duration of pumping, can be calculated by using the Theis equation:

$$s = \frac{Q \cdot b \cdot W(u)}{4 \cdot \pi \cdot K} \quad (3.1)$$

with:

$$W(u) = \int_u^\infty \frac{e^{-u}}{u} du \quad (\text{well function}); \quad (3.2)$$

and

$$u = \frac{r^2 S_s}{4K \cdot t} \quad (3.3)$$

where: s = drawdown (m), $S_s = \rho g (\alpha + \beta n)$ = specific storage (1/m), α , β = aquifer - and fluid compressibility (1/Pa), n = porosity (-), Q = production rate (m^3/s); K = hydraulic conductivity (m/s), r = radial distance between DST well and producing well (m), b = aquifer thickness (m), t = time period of production prior to DST (s).

There are two major complications to this method, one regarding the Theis equation itself and the other regarding the hydraulic parameters K and S_s . The Theis equation is strictly valid only under certain idealized conditions (e.g., Freeze and Cherry, 1979, p. 315-317; Langguth and Voigt, 1980, p. 150-151), that include a perfectly confined, homogeneous and isotropic aquifer with infinite extent. The values of n , K , Q , α and β , and hence S_s , generally are not known and must be estimated. Because of the integral form of the well function, the Theis method has to be applied manually and individually to each test. An

additional limiting factor is, therefore, the amount of time needed for data processing, particularly for a very large database.

To overcome the difficulties and lack of data, in applying the Theis solution, Tóth and Corbet (1986) assumed that, all other factors being constant, the effect of production is directly proportional to an interference index, I , defined as:

$$I = \log (t/r^2) \quad (3.4)$$

Several neighboring producing wells may influence the drawdown in a single DST. The nearest producing well does not necessarily have the biggest influence on the drawdown in the DST well, because production rates from wells farther away might be significantly larger. Based on the linearity of Equation 3.1, a cumulative interference index I_c is calculated as the sum of interference indices (ΣI) for all producing wells located within a defined minimum radial distance:

$$I_c = \Sigma [\log (t/r^2)] \quad (3.5)$$

Application of this equation requires knowledge of the distance between wells, and DST and production dates, information recorded by the industry and captured in the EUB and private databases. Thus, calculation of the interference index I_c can be easily automated and applied to large databases. The minimum radial distance from the DST well within which producing wells have an effect on the drawdown largely depends on aquifer permeability. Permeability heterogeneity, for example due to changes in lithology, fracturing, or faults, causes a wide range, commonly 2 – 20 km, in the value of the radius of influence (Rostron et al., 1995).

For all practical purposes, taking into account aquifer heterogeneity and possible missing or inconsistent data from producing wells, a semi-quantitative culling approach was used in this study. Considering only the well locations with the respective DST or production dates, an interference index was calculated for each DST well and the nearest producing

well according to Equation 3.4 using a computer code described by Rostron et al. (1995). In addition, the number of producing wells predating the DST within a radius of up to 50 km from each DST well were reported. This procedure was applied, on an aquifer-by-aquifer basis, only to the water-saturated zones, assuming that drawdown effects propagating vertically across aquitards are negligible. Hydraulic heads were calculated from the formation pressure for all DSTs (see chapter 2, Eq. 2.7) and contoured for each aquifer. Generally, a data point that creates closed contour lines indicates a source or sink for formation water flow, which could be due to: a) a natural fluid sink or source within the aquifer itself b) vertical flow into or out of an adjacent aquitard; c) vertical cross-formational flow into or out of an adjacent aquifer; or d) producing or injecting wells in the vicinity. Therefore, DSTs with a high interference index and/or a large number of producing wells in their vicinity were individually examined and rejected if they caused anomalies in the hydraulic head contours. Also, tests in the near vicinity of heavily producing hydrocarbon fields were checked more thoroughly, even if the DST was not from a producing unit, and rejected if the reported initial reservoir pressure was higher than that measured in the DST for a comparable depth, or an associated anomaly could not be explained by natural flow processes (a, b or c). Natural flow processes were deemed unlikely to have caused anomalies if there was no known mechanism to create a sink or source in the particular aquifer or confining aquitard, and if hydraulic head distributions in the directly adjacent aquifers did not show a corresponding source or sink that would support the possibility of cross-formational flow.

3.3 Data processing

3.3.1 Structure maps

The irregular distributions of well picks for each formation were transformed into a regular grid distribution using a least-squares gridding algorithm implemented by the Radian Mapping Software CPS-3. The computer grid was smoothed by a bi-harmonic filter and tied back to the control point data (Graf and Thomas, 1988), to achieve

maximum honoring of the original well data picks. To obtain a consistent framework of the general geology in the study area, a relatively coarse grid was used (24 x 24 nodes spaced 12.5 km apart). The number of picks generally increases from SW near the thrust and fold belt to the NE, and from the Precambrian up to the Cretaceous. Therefore, the computed surfaces might represent a relatively rough approximation of the stratigraphy, especially of deeper strata and in the area close to the thrust and fold belt.

The result is a three-dimensional representation of the succession of major stratigraphic surfaces in the undeformed part of the study area. The stratigraphic surfaces were used to allocate the hydrochemical and pressure data to the respective formations. The complete set of DST and chemistry data was run against the bounding surfaces of all aquifer units (Tab. 3.2) by comparing location and the elevation of each test interval against the interpolated surface grid elevation at each point. This process resulted in separate DST and chemistry files for each aquifer unit. Data points were checked individually for the reported driller's allocation of the respective test interval in cases of thin aquifers or thin confining units between aquifers (e.g., Viking aquifer: 5 – 50 m thickness), for which the resolution of the gridded surfaces was inadequate. Data were re-allocated if the driller's allocation conflicted with the mechanical allocation using the surface grids. The combination of a grid-based allocation of data and using the driller's stratigraphic allocation from the DST or chemistry report guarantees a higher reliability than using only one of the two methods.

3.3.2 Hydrogeochemical representation methods

The hydrochemical data in this study were used to: a) determine the origin and evolution of formation waters; b) in conjunction with hydraulic data, delineate flow paths; and c) calculate the in-situ density of formation waters.

Variations in the major ion hydrochemistry can be used to determine the origin and evolution of formation waters in sedimentary basins (i.e., Carpenter, 1978; Land, 1987;

Hanor, 1994 a, b). As most sediments are deposited in marine or marginal-marine environments, seawater is a useful reference solution against which formation waters are compared (Land, 1987). While salinity lower than that of seawater (35 g/L) usually is caused by mixing with meteoric water, the increase in the concentration of dissolved solids in brines (> 35 g/L) is mainly attributed to the evaporation of seawater and the dissolution of evaporites (Hanor, 1994).

During the evaporation of seawater various salts precipitate from solution, depending on their solubility, and causing a change in the relative concentration of ions in the remaining fluid. Generally, the trends of relative changes in concentration of any two dissolved ions during the evaporation of seawater is termed seawater evaporation trajectory (SET). Bromide-versus-chloride concentrations are a commonly used indicator for dissolved salts in formation waters (Carpenter, 1978). The Cl/Br-ratio remains constant during the evaporation of seawater until the point of halite saturation, after which Cl is preferentially precipitated, causing a decrease in the Cl/Br-ratio (Carpenter, 1978). Subsequent dilution by meteoric water does not change the Cl/Br-ratio any further, only both concentrations decrease, so that the dilution trend of Cl versus Br falls parallel and above the SET (Connolly et al., 1990; Hanor, 1994). On the other hand, halite dissolution causes a concentration of Cl in the residual solution, and the respective Br/Cl-ratios are lower than those along the SET. However, Br is rarely measured in standard industry analysis. The major cations also follow a distinct seawater evaporation-dilution trend (Carpenter, 1978). From the major ions, chloride acts as the most conservative, because, except for the dissolution and precipitation of Cl-salts, Cl is not involved in processes of water-rock interaction in the subsurface. Therefore, plots of the major cation concentrations of Na, Mg, and Ca against Cl concentrations in the formation waters were compared to experimentally derived evaporation-dilution trends (McCaffrey et al., 1986), to investigate whether the formation waters are evaporated or diluted seawater. If the data followed different trends, other processes had to be considered that might have affected the major ion chemistry (i.e., dissolution of evaporites, dolomitization, albitization).

Another useful method in the investigation of basinal brines is the comparison of Na, Ca, and Cl concentrations between formation waters and seawater. Davisson and Criss (1996) introduced a mathematical transformation of Na, Ca, and Cl concentrations that produces a linear slope of unity between the milliequivalencies of Na and Ca cations in numerous basinal fluids, including the Alberta Basin. The excess Ca and the Na deficit relative to seawater reference ratios are defined as (Davisson and Criss, 1996):

$$Ca_{\text{excess}} = \left[Ca_{\text{meas}} - \left(\frac{Ca}{Cl} \right)_{\text{sw}} \cdot Cl_{\text{meas}} \right] \cdot \frac{2}{40.08}$$

$$Na_{\text{deficit}} = \left[\left(\frac{Na}{Cl} \right)_{\text{sw}} \cdot Cl_{\text{meas}} - Na_{\text{meas}} \right] \cdot \frac{1}{22.99}$$

where the concentrations (in mg/L) of the ions measured (meas) in a sample are referred to those in seawater (sw), and the numerical constants convert the results to meq/L. Plotting Ca_{excess} versus Na_{deficit} values of more than 800 samples from various basins and aquifer lithologies, Davisson and Criss (1996) derived a highly correlated regression line that they termed Basinal Fluid Line (BFL):

$$Ca_{\text{excess}} = 0.967(Na_{\text{deficit}}) + 140.3,$$

where the unit slope is interpreted to indicate that the albitization of plagioclase (2 Na for 1 Ca exchange ratio) is the predominant reaction to control the chemistry of deep formation waters. The intercept of 140.3 for the BFL can be attributed to the dissolution of halite prior to albitization, whereas the trend of albitization of seawater only would start at the origin of the excess-deficit graph (Davisson and Criss, 1996).

3.3.3 Contouring of hydrochemical data

The distributions of salinity and selected ion concentrations (g/L) were contoured manually, which allowed for the better integration of geological and hydraulic information for extra- and interpolation purposes in areas of low data density. For

example, geological boundaries, like the extent of carbonate platforms, represent discontinuities in the aquifer geometry, which affect the distribution and flow paths of formation fluids and which is difficult to account for in mechanical contouring procedures. A typical gridding algorithm does not recognize aquifer heterogeneity and the resulting contours would likely cross geological boundaries, which subsequently would have to be changed in order to achieve an interpretation of flow patterns that is consistent with the geology. Plots of the study area showing data locations and concentration values were generated for each aquifer, using the Alberta Geological Survey cartographic system (AGSSYS). These maps were imported in the CANVAS graphics program, in which the data points were hand-contoured. Contours were interpolated in areas of low data density data by comparing and fitting the distribution of chemical data to patterns observed in the complementary hydraulic and geological maps. All data points were honoured within their range of accuracy as manifested in the respective contouring interval.

Usually, the analytical errors in the chemical analyses are significantly smaller than errors introduced by sampling techniques and potential dilution with drilling mud. It is difficult to estimate the magnitude of practical errors in the remaining hydrochemical data that passed the mechanical culling process because the potential mixing or dilution of formation water samples with drilling fluids cannot be determined quantitatively from the analytical report. Therefore, a conservative error of 10 % for salinity was chosen, based on the variance of concentrations in chemical analyses from the same water sample or different samples from the same well and depth range. This translated to a contour interval of at least 10 % of the average concentration, which was used for the mapping of salinity (TDS) in the various aquifers.

3.3.4 Processing of pressure data

The pressure data from DSTs were plotted versus depth (p(d)-plot) and versus elevation (p(z)-plot), and equivalent hydraulic heads were calculated and contoured. In addition, in

the Elk Point aquifers the impelling force vectors acting on the fluid were constructed. Due to the complexity and controversies regarding the representation of variable-density fluid flow in sedimentary basins, Chapter 2 presented a detailed discussion on the theoretical aspects and defined the variables and equations for the calculation of the hydraulic gradient and the impelling force. The measurement accuracy and mechanical errors associated with formation pressures determined from DSTs have to be taken into account in addition to the theoretical errors associated with using equivalent hydraulic heads in the flow representation. Only then, the accuracy in the flow representation, using hydraulic head maps versus impelling force vectors, can be evaluated. Following parameters may have errors associated with them: fluid pressure p and measurement elevation z for calculating hydraulic heads, and in addition fluid density ρ and aquifer slope ∇E for calculating force vectors.

The accuracy as specified by various manufacturers ranges between 0.025 and 0.25 % of the full scale for newer pressure gauges (1970 – 2000) and was as low as 0.5 % for gauges from the 50's and 60's (from H. Reid, course manual for DST interpretation). This translates to a maximum error of approximately to ± 200 kPa (accepted pressure difference between first and second shut-in measurement for a C quality DST) or ± 20 m of hydraulic head. On the other hand, errors introduced by the mechanical procedure of the test are much larger, and empirically determined errors in pressure measurements generally increase with depth and range between 170 and 650 kPa (Bradley, 1975; Bredehoeft, 1965; Dahlberg, 1995). Assuming freshwater density, this translates to a hydraulic head difference that varies approximately between 17 m for shallow aquifers and a maximum of 65 m for deep aquifers. This relatively large methodology error may be reduced by only using DSTs of A, B, and C quality and Horner-extrapolated pressures. Errors associated with the depth measurement and the land surveying of the kelly bushing (KB) elevation are comparably small, but only can be estimated to be in the range of a few metres. A contour interval of 50 m was therefore chosen in most of the hydraulic head maps for representation and analysis, which is the contour interval that typically has been used in many previous regional-scale hydrogeological studies, based on industry

pressure data in the Alberta Basin (e.g., Tóth, 1978; Bachu and Underschultz, 1993; Rostron and Tóth, 1997; Rostron et al., 1997; Anfort et al., 2001).

The fluid density was calculated based on the salinity of the formation water, pressure, and temperature using empirical equations that were fit to laboratory experiments (Rowe and Chou, 1970; Kestin et al., 1981; Appendix D). This expression was used in various numerical models of formation water flow in sedimentary basins (e.g., Garven, 1985, 1989; Raffensberger and Garven, 1995; Person and Garven, 1994; Appold and Garven, 1999). Kestin et al. (1981) estimate the accuracy of the calculated densities to be $\pm 0.5\%$, which translates to $\pm 5 \text{ kg/m}^3$ for freshwater (1000 kg/m^3). However, errors associated with the measured pressure, salinity, and temperature values have to be added. The pressure was obtained from the DST itself and salinities from distribution maps (grids). In-situ temperatures were calculated from integral geothermal gradients in the Western Canada Sedimentary Basin within an estimated accuracy of a few degrees Celsius (Bachu and Burwash, 1994).

The sensitivity of the calculated formation water density was determined by changing pressure, salinity and temperature in the empirical density equation (Rowe and Chou, 1970; Kestin et al., 1981) within the respective error ranges for three theoretical cases of representative pressure, salinity and temperature conditions (Table 3.4). Generally, the error in salinity causes the largest difference in the value of the calculated formation water density ($\sim \pm 7 \text{ kg/m}^3$), except for formation water with low salinity, which is slightly more affected by errors in temperature ($\pm 1.0 \text{ kg/m}^3$) than errors in salinity ($\pm 0.7 \text{ kg/m}^3$). In comparison, changes in pressure within a range of 400 kPa have almost no affect on the calculated density ($\pm 0.1 \text{ kg/m}^3$). An overall error of at least $\pm 15 \text{ kg/m}^3$ in the calculated formation water density results from adding the mathematical error of $\pm 5 \text{ kg/m}^3$ (Kestin et al., 1981) to the confidence range of approximately $\pm 10 \text{ kg/m}^3$ that is caused by the inaccuracy in salinity, temperature and pressure.

	Ref.	Salinity: +/- 10 %	Temperature: +/- 5°C	Pressure: +/- 200 kPa			
Shallow depth							
Pressure (MPa)	5	5	5	5	5	4.8	5.2
Salinity (wt%)	0.01	0.009	0.011	0.01	0.01	0.01	0.01
Temperature (°C)	20	20	20	15	25	20	20
Density (kg/m ³)	1008	1007	1008	1009	1006	1008	1008
$\Delta \rho$ (kg/m ³)		1	0	-1.0	2	0	0
Intermediate depth							
Pressure (MPa)	18	18	18	18	18	17.8	18.2
Salinity (wt%)	0.12	0.11	0.13	0.12	0.12	0.12	0.12
Temperature (°C)	65	65	65	60	70	65	65
Density (kg/m ³)	1071	1064	1079	1074	1068	1071	1071
$\Delta \rho$ (kg/m ³)		7	-8	-3	3	0	0
Large depth							
Pressure (MPa)	29.5	29.5	29.5	29.5	29.5	29.3	29.7
Salinity (wt%)	0.2	0.19	0.21	0.2	0.2	0.2	0.2
Temperature (°C)	95	95	95	90	100	95	95
Density (kg/m ³)	1116	1108	1124	1119	1113	1116	1116
$\Delta \rho$ (kg/m ³)		8	-8	-3	3	0	0

Table 3.4: Sensitivity of the calculated density with changing salinity, temperature and pressure. Only one parameter was changed from the reference conditions (Ref.) in each column within its respective error range, while the other two were kept constant.

Accuracy of equivalent hydraulic heads and flow-driving force vectors

According to the theoretical discussion in Chapter 2, the effect of density variations on the flow representation becomes significant only when the pressure-related force component is small compared to the density-related force component, i.e. $\nabla H_0 \approx 0$ and the aquifer slope and difference between water density and reference density are large. However, the hydraulic gradient is calculated using DST pressures measurements that contain a certain degree of error. The force vectors have an even higher degree of uncertainty because errors in the pressure-related force component (hydraulic gradient) have to be added to errors in the density-related force component due to the inaccuracy in

the density calculation. Therefore, it is critical to compare the magnitude and accuracy of the hydraulic gradient to the magnitude and accuracy of the density-related force component, before the impact of density variations on the flow representation can be assessed.

According to Equations 2.25 and 2.28, the driving force along the aquifer slope can be represented by the sum of its pressure- and density-related components:

$$F^* = -\rho_0 \cdot g(\nabla H_0 + \frac{\rho - \rho_0}{\rho_0} \cdot \nabla E) = -\rho_0 \cdot g(F_p + F_\rho), \quad (3.6)$$

Therefore, the error in the force magnitude ΔF is the sum of the errors in its two components:

$$\Delta F = \Delta F_p + \Delta F_\rho. \quad (3.7)$$

The four steps for constructing the impelling force vector are:

- (1) Equivalent hydraulic heads H_0 and hydraulic gradients $\text{grad } H_0$ are calculated for each point using a reference fluid density and DST pressures.
- (2) A value for the elevation gradient $\text{grad } z$ is calculated either from a grid of DST test elevations or a grid of the aquifer structure. Resulting gradients from these two grids are comparable for an aquifer with a large lateral extent compared to its thickness. However, using the grid of the aquifer structure is preferred because the coverage of stratigraphic data is better than that of DST data for any aquifer.
- (3) A relative density term $\rho^* = \frac{(\rho - \rho_0)}{\rho_0}$ is calculated for each point and multiplied with the value of the elevation gradient.
- (4) The resulting impelling force vector is constructed by adding the x and y components of $\text{grad } H_0$ and $\frac{(\rho - \rho_0)}{\rho_0} \cdot \nabla z$ at every point.

Practically, the hydraulic gradient between two points (wells or grid points) in an aquifer is approximated by the difference in hydraulic heads divided by the distance l between the two points: $\nabla H_0 = \frac{H_{01} - H_{02}}{l}$. (3.8)

A maximum error in equivalent hydraulic head ΔH_0 of ± 25 m causes the error in the pressure-related force component to be:

$$\Delta F_p = \frac{2 \cdot \Delta H_0}{l} = \frac{50 \text{ m}}{l} \quad (3.9)$$

Practically, the slope of the aquifer is approximated by the difference in elevation of the aquifer top or bottom between two points: $\nabla E = \frac{z_1 - z_2}{l}$ (3.10)

A maximum error $\Delta \rho$ of $\pm 15 \text{ kg/m}^3$ in the density values and $\Delta z = \pm 2.5 \text{ m}$ in elevations results in an uncertainty in the maximum pressure-related force component of approximately:

$$\begin{aligned} \Delta F_p &= \frac{\partial F_p}{\partial \rho} \cdot \Delta \rho + \frac{\partial F_p}{\partial E} \cdot \Delta z = \frac{1}{\rho_0} \cdot \frac{z_1 - z_2}{l} \cdot \Delta \rho + \frac{2 \cdot \Delta z}{l} \cdot \frac{\rho - \rho_0}{\rho_0} \\ &= \frac{15 \cdot (z_1 - z_2)}{1000 \cdot l} + \frac{5 \text{ m} \cdot 150}{1000 \cdot l} = \frac{0.015 \cdot (z_1 - z_2) + 0.75 \text{ m}}{l} \\ &= 0.015 \cdot \nabla E + \frac{0.75 \text{ m}}{l} \end{aligned} \quad (3.11)$$

for a maximum density difference $\rho - \rho_0 = 150 \text{ kg/m}^3$.

The dependence on the distance l of the errors in the force and force components infers that practically it is impossible to accurately determine low force magnitudes over relatively short distances as shown in the following example, assuming a maximum value

for the density-related force component and relatively low value for the pressure-related force component.

Example 1:

$\rho_0 = 1000 \text{ kg/m}^3$, $\rho = 1150 \text{ kg/m}^3$ (maximum density difference in the study area),

$\nabla E = 0.02$ (maximum aquifer slope in the study area)

$\nabla H_0 = -F_\rho/2 = -0.0015$ (DFR = 2)

a) $l = 10 \text{ km}$

$$\begin{aligned} \frac{F^*}{-\rho_0 \cdot g} &= F_\rho \pm \Delta F_\rho + F_\rho \pm \Delta F_\rho = -0.0015 \pm 0.005 + 0.0030 \pm 0.0004 \\ &= 0.0015 \pm 0.0054 \end{aligned}$$

$$DFR = \frac{|F_\rho|}{F_\rho} \pm \left(\frac{\Delta F_\rho}{F_\rho} + \frac{\Delta F_\rho}{F_\rho} \right) \cdot DFR = 2 \pm 7$$

b) $l = 50 \text{ km}$

$$\begin{aligned} \frac{F^*}{-\rho_0 \cdot g} &= -0.0015 \pm 0.001 + 0.0030 \pm 0.0003 \\ &= 0.0015 \pm 0.0013 \end{aligned}$$

$$DFR = 2 \pm 1.5$$

c) $l = 100$ km

$$\frac{F^*}{-\rho_0 \cdot g} = -0.0015 \pm 0.0005 + 0.0030 \pm 0.0003$$

$$= 0.0015 \pm 0.0008$$

$$DFR = 2 \pm 0.9$$

The previous example shows that:

- 1) the error in the pressure-related force component ('hydraulic gradient') increases with decreasing distance over which it is determined. The relative error is larger than 1 to a distance l of approximately 40 km (Fig. 3.1 a);
- 2) the maximum error in the density-related force component for the case of maximum density difference and aquifer slope is ± 0.0003 , increasing only slightly with decreasing distance. The relative error is approximately 10 %. This error is smaller than the error in the pressure-related force component for measurement distances $l < 300$ km (Fig. 3.1 a);
- 3) small differences in equivalent hydraulic heads; in this case a pressure-related force component having half the magnitude of the density-related force component, cannot be accurately determined over distances < 50 km (Fig. 3.1 a) due to the large errors associated with the pressure measurements. Over these distances, it also is not meaningful to calculate the force vector by adding its density-related component, because the magnitude of the total force is still smaller than its total error.

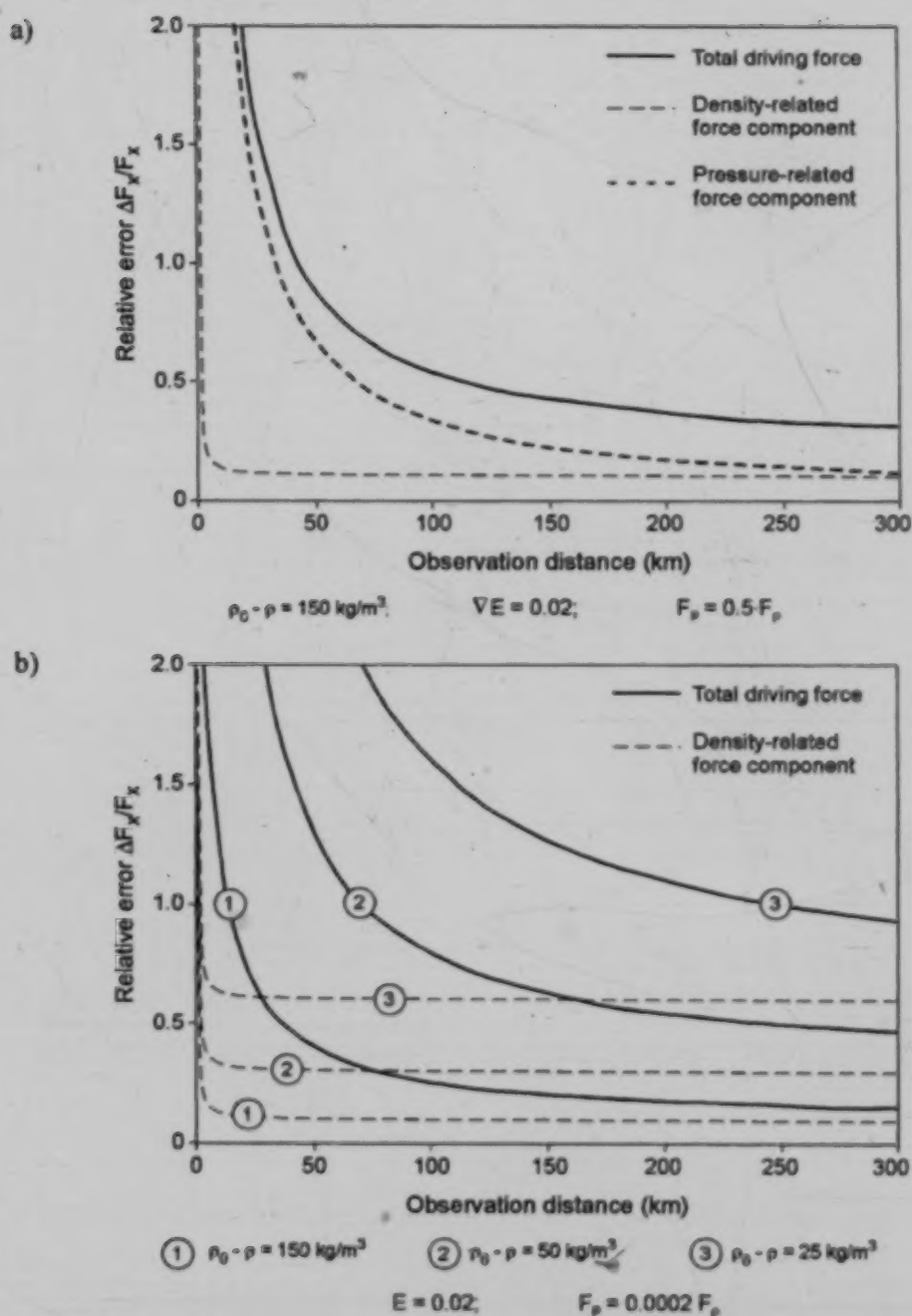


Figure 3.1: Change of the relative errors of the driving force magnitude and its pressure- and density-related components with distance over which the force was calculated for: a) Maximum density difference in the study area, maximum aquifer slope and a DFR = 2, and b) three difference density ranges, maximum aquifer slope, and $F_p \ll F_p$. Equations 3.6, 3.7, 3.9, and 3.11 were used to calculate the relative error for the driving force and its components.

More generally speaking, the theoretical gain of accuracy in the representation of flow by calculating force vectors is limited to a certain scale of observation by the measurement errors in the pressure-related force component. Even for the most extreme case, when equivalent hydraulic heads cannot be used to represent water flow in the study area (i.e., 150 kg/m^3 difference between actual formation water density and reference density, a maximum aquifer slope of 0.02, and $F_p \gg F_\rho$), the general direction of flow can be inferred accurately from driving force vectors only if the relative error is smaller than 1.0; hence if the force is determined of a distance larger than 20 km (Fig. 3.1 b, Case 1). However, if the difference between formation water density and reference density is only 50 kg/m^3 for the same pressure conditions in the aquifer, the threshold for the observation distance beyond which the general flow direction may be determined accurately from force vectors is approximately 65 km (Fig. 3.1 b, Case 2). Obviously, if the pressure-related force component is close to zero and the density-related force component is small (Fig. 3.1 b, Case 3), the flow direction in the aquifer cannot be clearly determined by either equivalent hydraulic heads or force vectors under 250 km, approximately the range of the study area. Consequently, within the appropriate error margins of the impelling force, the flow can be characterized only as $\pm$ stagnant.

Consequences from theoretical and practical considerations for the interpretation of pressure data

Two aspects have to be considered when choosing the appropriate representation method, equivalent hydraulic heads versus driving force vectors, for the flow of variable-density formation water in sloping aquifers: 1) the magnitude of the theoretical error that is due to the neglect of the density-related force component in equivalent hydraulic head interpretations (see Chapter 2), and 2) the effect of practical errors on equivalent hydraulic heads and force vectors that is caused by the inaccuracies in pressure measurements and density calculations. Ideally, theoretical errors should be avoided and the level of uncertainty should be incorporated in the method of flow representation. The previous section showed that the errors associated with the pressure measurements are the

principal cause for the inaccuracies in both, gradients calculated from equivalent hydraulic heads and driving force vectors, and that the relative error depends on the distance over which these two are measured. Consequently, only general flow directions can be inferred from any method that uses pressure measurements from DSTs. Theoretically, driving force vectors are the accurate method for the representation of variable-density flow in sloping aquifers (see Chapter 2). However, the driving force vector at a specific point can be calculated practically only between two wells or within a grid, because the vector is composed of gradients of hydraulic heads and aquifer structure. Thus, for low hydraulic gradients and $DFR > 1$, the spacing between wells or grid points would have to be relatively wide (20 – 250 km) compared to the dimensions of the study area, depending on the reference density and aquifer slope, before force vectors accurately indicate the general flow direction within the appropriate error range (Fig. 3.1). The appropriate result would be either a coarse grid with even spacing between flow vectors that indicates the general flow direction in the study area, but has a bad resolution in areas with high hydraulic gradients, or an uneven distribution of grid points (high resolution in area of high hydraulic gradients and low resolution in areas of low hydraulic gradients), for which the errors vary depending on the grid spacing, and which is cumbersome to construct. Contour maps of equivalent hydraulic heads have the advantage that they are easy to construct and that the contour interval, if chosen accordingly, directly reflects the accuracy of the point data. The disadvantage is the theoretical error that is made when inferring flow directions from hydraulic gradients and ignoring the density effects. Nevertheless, this theoretical error is critical only if hydraulic gradients are low compared to the density-related force component, and the error can be minimized by reducing the difference between the reference density and the actual formation water density (see Chapter 2).

In summary, the measurement errors associated with pressure data from DSTs cause inaccuracies in both equivalent hydraulic heads and driving force vectors. This imprecision outweighs the theoretical accuracy of the driving force vectors compared to equivalent hydraulic heads for most pressure-, density- and aquifer slope conditions and scales of observation in the study area. As a consequence, contour maps of equivalent hydraulic heads were used for the interpretation of flow in this study. The maximum

difference between reference density and formation water density in each of the three hydrostratigraphic groups in the study area is 50 kg/m^3 , when choosing as reference density the average between the respective minimum and maximum densities (Tab. 3.5). Reference densities of 1040 kg/m^3 , and 1090 kg/m^3 were used to calculate equivalent hydraulic heads in the Jurassic-Mississippian, and the Cambrian-Devonian hydrostratigraphic groups, respectively. Because of the relatively small difference of formation water density in the Tertiary-Cretaceous hydrostratigraphic group ($\rho_{\min} - \rho_{\max} = 50 \text{ kg/m}^3$) freshwater density could be used as a reference density, still resulting in the same level of accuracy as in the other hydrostratigraphic groups.

Hydrostratigraphic Group	Salinity Range (g/L)	Density Range (kg/m^3)
Tertiary-Cretaceous	1.7 - 10.5	995 - 1045
Jurassic-Mississippian	35 - 165	1000 - 1080
Cambrian-Devonian	115 - 300	1040 - 1140

Table 3.5: Salinity and density range in the various hydrostratigraphic groups in the study area. The fluid density was calculated based on the salinity of the formation water, pressure, and temperature using empirical equations that were fit to laboratory experiments (Rowe and Chou, 1970; Kestin et al., 1981; Appendix D).

The distribution of equivalent hydraulic heads was contoured manually, for the same reasons and the using the same procedure as described for the contouring of hydrochemical data (Section 3.3.3). All data points were honoured within their range of accuracy as manifested in the contouring interval of 50 m. Therefore, hydraulic head differences can be calculated only to a resolution of 50 m over any distance l (Eq. 3.9). Hydraulic gradients accurately indicate the general flow direction, for $\nabla H_0 > F_\rho$ (DFR

< 1) and $l < \frac{50 \text{ m}}{F_\rho}$. The critical distance beyond which the flow direction inferred from

a hydraulic head difference of 50 m might be reversed due to density effects exists for a maximum aquifer slope of 0.02 and maximum difference between reference and

formation water density of 50 kg/m^3 : $l_{crit} = \frac{50 \text{ m}}{\max F_\rho} = \frac{50 \text{ m}}{0.001} = 50 \text{ km}$. For the same

conditions, driving force vectors accurately indicate the general flow direction if measured over at least 65 km (Fig. 3.; Case 2). These critical distances will be larger for less extreme density differences and aquifer slopes. For all practical purposes, areas in which the lateral distance between 50 m contour lines larger than 50 km have to be examined more closely with respect to the actual aquifer slope and formation water density.

Note: The impelling force vectors that were calculated for the Elk Point example in Chapter 2, only considered the theoretical aspects of the difference between equivalent hydraulic heads and impelling force vectors for the representation of formation water flow. If data accuracy were considered in the Elk Point example, a 50 m contour interval instead of 10 m would be appropriate. Then, the general flow direction could be inferred only in the area of relatively high hydraulic gradients and large force magnitudes in the east, while flow in the west would have to be interpreted as +/- stagnant.

CHAPTER 4:

GEOLOGICAL AND TECTONIC SETTING

4.1 Introduction

The study area is located at the western edge of the Alberta Basin, which is part of the Western Canada Sedimentary Basin (WCSB) (Fig. 4.1). The undeformed part of the Alberta Basin is bounded by the Tathlina High in the north, the Bow Island Arch, separating it from the Williston Basin, in the southeast, the Precambrian Shield in the northeast and the Rocky Mountain thrust and fold belt in the west. The basin consists of a wedge of Phanerozoic sediments thickening southwestward from the exposed Precambrian Shield to a thickness of more than 6 km along the Cordilleran deformation front.

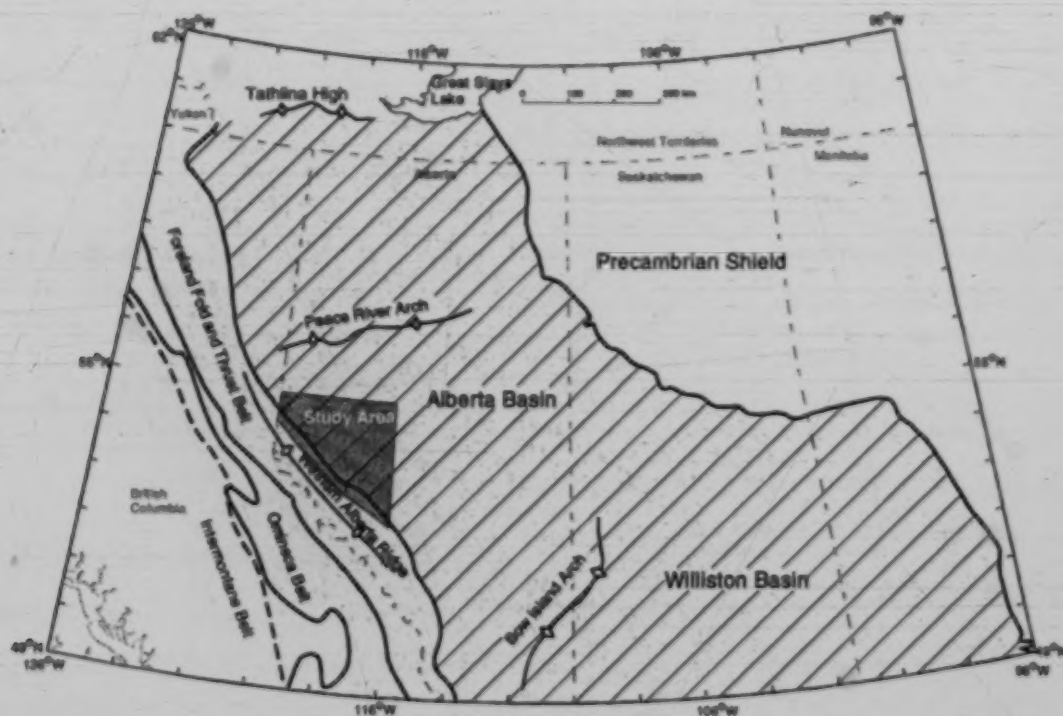


Figure 4.1: Structural elements of the Western Canada Sedimentary Basin. The grey shading represents the area of preserved sedimentary rocks of the WCSB; the hatched area shows the undeformed part of the basin (modified after Wright et al., 1994).

The study area extends from the Foothills within the Rocky Mountain thrust and fold belt to about 200 km into the undeformed part of the basin (Fig. 4.2). The sediment thickness ranges between approximately 3 km in the northeast to 6 km in the southwest.

The sedimentological history of the Alberta Basin can be differentiated into two main phases. The "platform stage" (Proterozoic to Jurassic) represents a mainly transgressive onlap of dominantly marine sediments along the passive margin of the North American Craton. The boundary between the craton and allochthonous terranes lies approximately between the Omineca Belt and the Intermontane Belt (Fig. 4.1). In the "foreland stage" (Jurassic to Paleocene) the former sediments were compressed as a result of the Columbian (Jurassic-Early Cretaceous) and Laramide (Mid-Late Cretaceous-Tertiary) Cordilleran orogenies, and syn- as well as post-orogenic, dominantly clastic, deltaic to fluvial sediments were deposited (Porter et al., 1982).

4.2 Regional structural geology

The study area can be divided into two structural provinces: 1) Interior Plains (Bally et al., 1966), which represents the undisturbed part, and 2) the deformed part of the basin, i.e., the Rocky Mountain Thrust and Fold Belt (Monger, 1989). These two parts of the basin are separated by the Paleozoic and Mesozoic deformation fronts that represent the limit of Cordilleran deformation in the two major sedimentary assemblages, respectively. The boundary between the Foothills and Front Ranges in the southern part of the study area is the McConnell Thrust (Fig. 4.2), whereas the Nikanassin Thrust is considered the boundary further north (Lebel et al. 1996).

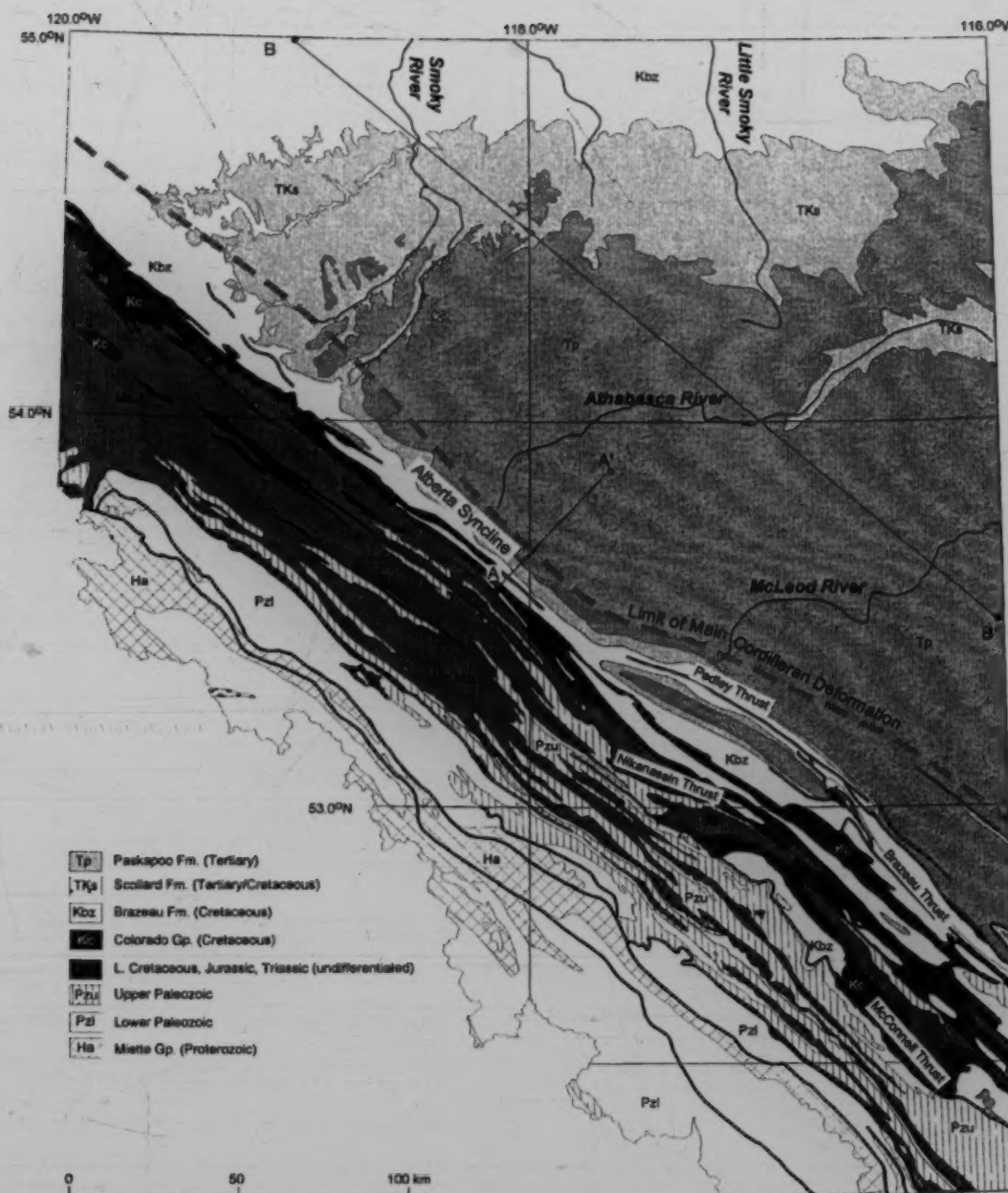


Figure 4.2: Bedrock geology in the study area (modified from Hamilton et al., 1997). Cross sections A - A' and B - B' are shown in Figures 4.3 & 4.5, respectively.

The structure of the Foothills is formed by east-to-northeast verging listric thrusts and associated decollement folds. Thrust sheets consist mainly of Paleozoic carbonates, overlain by folded Mesozoic clastic rocks (Bally et al., 1966; Price, 1986). Differences in the structural style of the thrusting are largely controlled by lithology and, hence, competence of the involved strata. Thick, competent carbonate and sandstone successions cause the development of thick, laterally extensive thrust sheets, whereas less competent assemblages of inter-layered sandstone and shales or carbonates and shale show the development of folds (Monger, 1989).

Within the eastern edge of the thrust and fold belt, a triangle zone is defined, which is underlain by a subhorizontal foreland-verging thrust that ends against a foreland-dipping thrust (Charlesworth et al., 1987). The eastern boundary of this triangle zone is represented by the Pedley Thrust (Fig. 4.3), which back-steps northeastward into the Robb Fault (Lebel et al., 1996). These thrust faults die out northeastwards in the Alberta Syncline, which forms the transition zone between the Foothills and Plains regions.

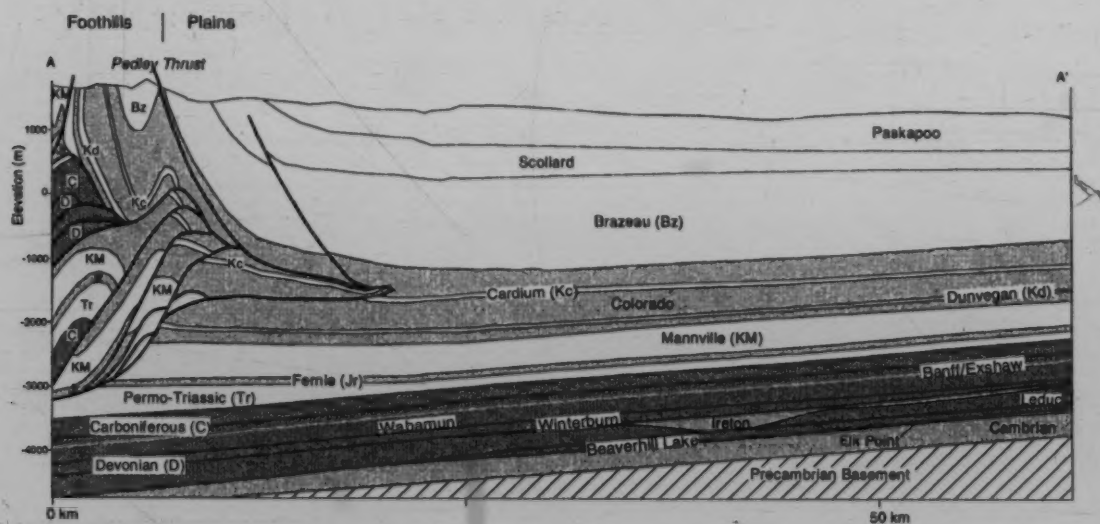


Figure 4.3: Geological dip cross section showing general lithology in the undeformed part of the basin and the structure of the triangle zone (structural part modified from Langenberg, 1992). See Fig. 4.2 for line of cross section.

4.3 Passive margin succession (Proterozoic – Jurassic)

The crystalline Precambrian basement forms the base of the passive margin sedimentary succession (Fig. 4.4). Structural features of the basement that affected sedimentation in the study area are the Peace River Arch to the north and the Western Alberta Ridge along the deformation front in the west (Fig. 4.1). The extent of the latter is not very well defined because of Paleozoic and Mesozoic deformation. Both structures formed topographic highs during the Paleozoic and, therefore, played an important role for the control of sedimentation during that time. Proterozoic sediments are exposed only in the mountain ranges and consist of coarse clastics of the Gog and Miette Groups (Rickets, 1989; Ross et al., 1989).

Cambrian sediments accumulated on the ancestral continental shelf during periods of rifting and extension (Cecile et al., 1997). Quartz sandstone forms the base of the Cambrian ('Basal Sandstone'), whereas the middle and late Cambrian mainly consists of mixed carbonates and clastics (Slind et al., 1994; Hein and Nowlan, 1998). The top of the Cambrian represents a major hiatus, as the Silurian to Lower Devonian strata are absent in the study area due to either erosion or non-deposition. Parallel to the axis of the Peace River Arch, the Cambrian was completely eroded as well, and is absent in the northwestern corner of the study area (Fig 4.5a).

The Middle to Upper Devonian succession was deposited during a major marine transgression. This succession can be broken down into a number of cycles, as represented respectively by the sediments of the Elk Point, Beaverhill Lake, Woodbend, Winterburn and Wabamun Groups (Moore, 1989).

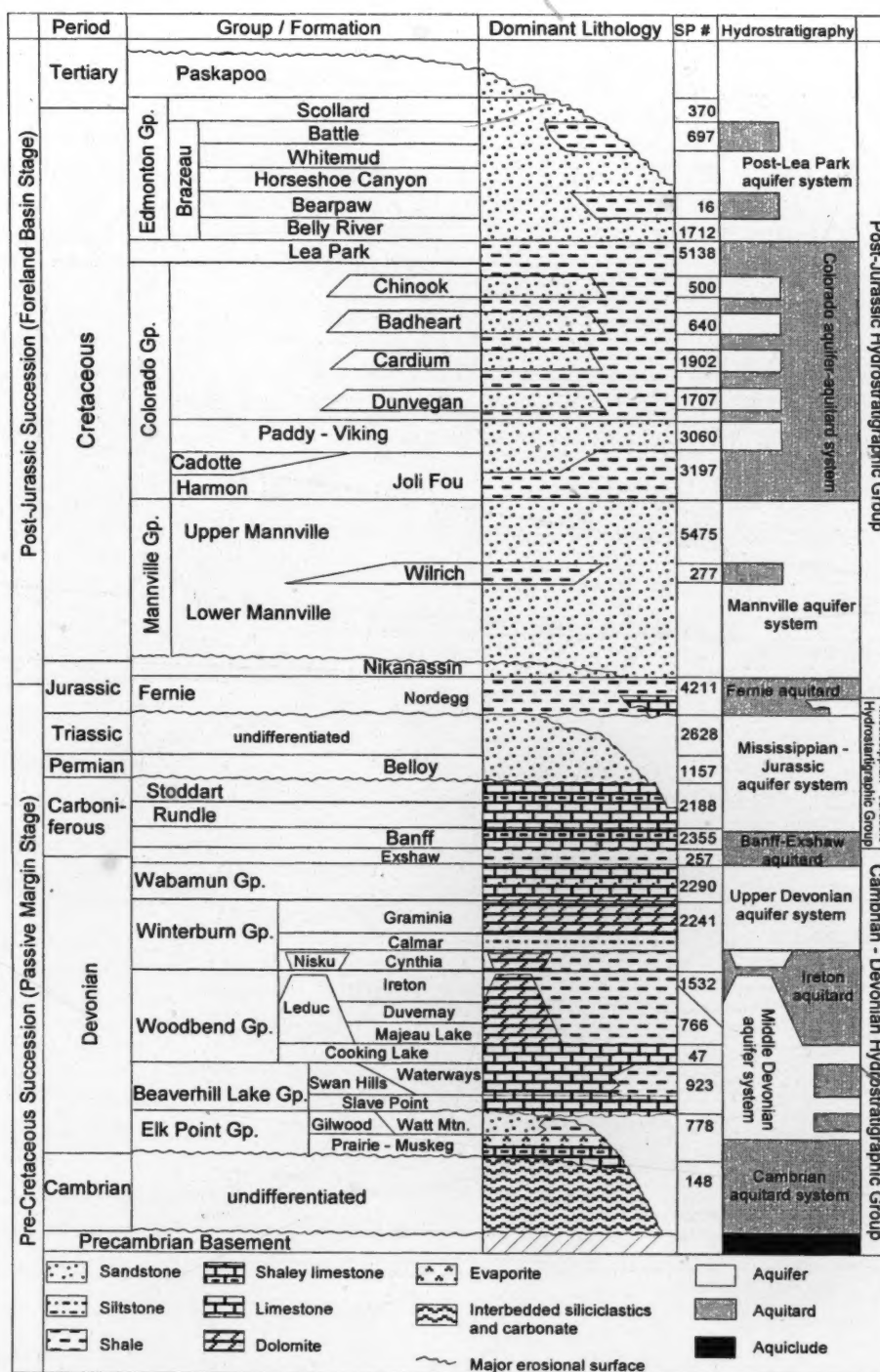


Figure 4.4: Stratigraphy, general lithology and general hydrostratigraphy of the sedimentary bed-rock succession in the study area. SP # = Number of stratigraphic picks used for the construction of formation surfaces.

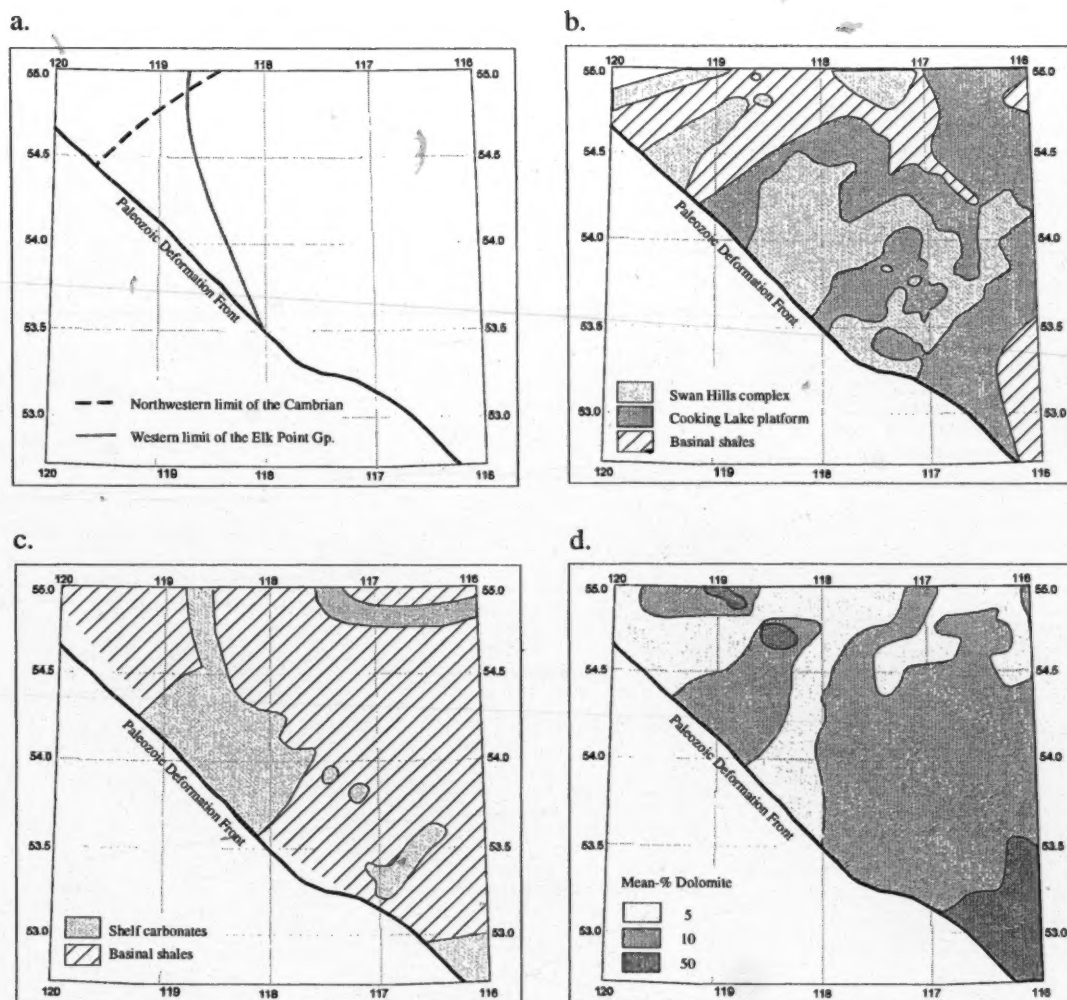


Figure 4.5: Various boundaries of Paleozoic strata in the study area in ascending order: a) erosional limits of the Cambrian and the Middle Devonian Elk Point Group., b) extent of carbonate platforms in the Middle Devonian Beaverhill Lake and Upper Devonian Woodbend groups, c) Lower Winterburn Group lithofacies, d) distribution of dolomite in the Wabamun Group. (modified from Mossop and Shetsen, 1994).

Elk Point Group sediments were not deposited in the areas of the former Peace River landmass and the Western Alberta Ridge. The youngest formation of this group, the Prairie, is present only in the northeastern part of the study area. The Prairie Formation consists of mixed clastics and carbonates and is overlain by interbedded anhydrites and dolostones of the Muskeg Formation, which are overlain by interbedded shales, sandstones and dolostones of the Watt Mountain/Gilwood Formation (Meijer Drees et al., 1994).

Platform (Slave Point Fm.) and reef (Swan Hills Fm.) carbonates of the Beaverhill Lake Group successively onlap the Precambrian basement and the Cambrian and Elk Point Group sediments (Fig. 4.6). In the study area these carbonates form the Swan Hills Complex (Fig. 4.5b), which is capped by carbonaceous shales of the Waterways Formation (Oldale and Munday, 1994).

There is a transition from Swan Hills carbonates into platform carbonates (Cooking Lake Fm.) of the Woodbend Group (Fig. 4.5b) with overlying reefs (Leduc Fm.). The latter two form the Southesk Cairn Complex, which is overlain by shales and carbonaceous shales of the Majeau Lake, Duvernay and Ireton formations. Where the Ireton shales are thin or absent, the Leduc reefs are in direct contact with the overlying Nisku Formation, the lowest part of the Winterburn Group (Switzer et al., 1994).

The lower Winterburn Group represents a continuation of shale deposition (Cynthia Fm.) with the exception of isolated Nisku pinnacle reefs and a narrow band of shallow shelf carbonates (Fig. 4.5c), all being overlain by a thin siltstone layer (Calmar Fm.). The upper part of the succession is formed by thick carbonates of the Blue Ridge Member and Graminia Formation, of which the uppermost part consists of a thin, regional extensive silt layer that represents the boundary to the upper Devonian Wabamun Group (Switzer et al., 1994).

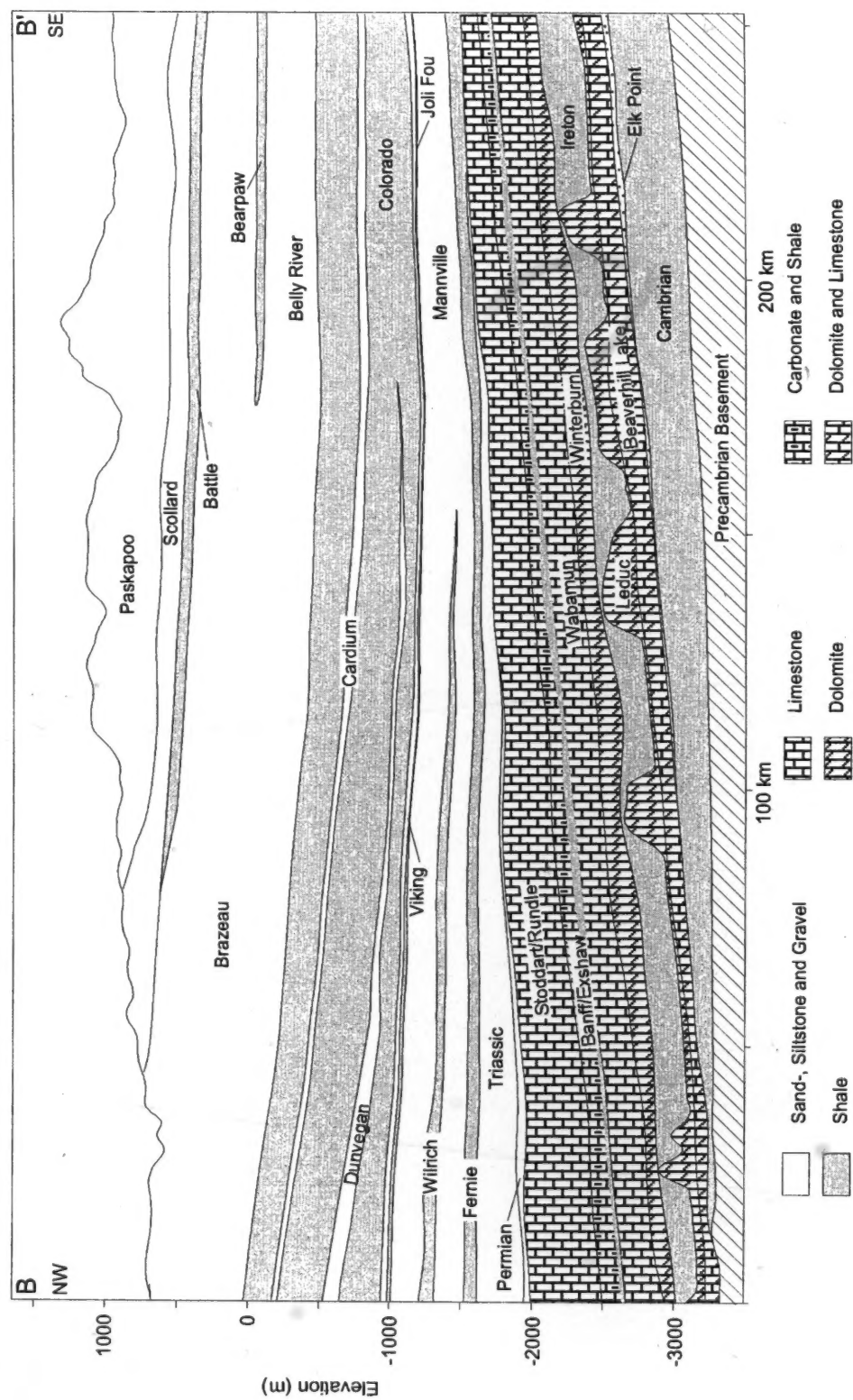


Figure 4.6: Geological cross section (B - B') sub-parallel to the deformation front showing general lithology distribution. See Figure 4.2 for line of cross section.

The Wabamun Group consists of massive, partly dolomitized carbonates. Generally, the lithofacies in the Wabamun Group change basin-wide southeastward from limestone to dolomite to evaporites (Andrichuk, 1960) (Fig. 4.5d). The limestone content increases upward, while dolomite and evaporites decrease (Saller and Yaremko, 1994). The boundary between the Devonian and Carboniferous systems lies in the overlying dark shales of the Exshaw Formation.

The Carboniferous succession was deposited on the by that time downwarped and downfaulted, western margin of the North American plate, caused by the Antler orogeny, and continued southward into the Antler Foreland basin of the western United States (Richards, 1989). The Exshaw Formation is a rather thin layer (< 50 m) of dark, organic shales and siltstones. The shales continue in the much lower part of the Banff Formation, whereas the upper two thirds consist of heterogeneous carbonate ramp deposits and siliciclastics (Richards et al., 1994). The overlying Rundle Group represents a transgressive-regressive sequence, which mainly consists of carbonate platform and ramp deposits, as well as minor evaporites and siliciclastics (Richards, 1989). The dominantly sand- to siltstones of the Stoddart Group at the top of the succession probably were deposited in an estuarine environment with associated deltas (Richards, 1989). The top of the Carboniferous forms a major unconformity due to subaerial erosion that cuts through several formations and started during the Late Carboniferous.

Permian, Triassic and Jurassic strata successively overlie the Carboniferous formations. Sediments of the Permian Belloy Formation cover only about 50 % of the study area (Fig. 4.7a) and consist dominantly of siliciclastics that become increasingly carbonaceous towards the deformation front. The top of the Permian forms an erosional boundary with the Triassic strata, but may be directly overlain by Jurassic sediments in small zones in the east, along the Triassic erosional edge (Fig. 4.7a).

The Triassic succession represents a coarsening-upward cycle deposited on a topographically low, tectonically stable continental shelf along the western margin of the

North American craton (Gibson and Barclay, 1989). Shales and siltstones form the base, overlain by silt- to sandstones, followed by sandstones and evaporites (Edwards et al., 1994). The top of the Triassic succession is a major erosional unconformity, with increasingly older formations subcropping underneath Jurassic strata from west to east. The Triassic is completely eroded at the eastern boundary of the study area.

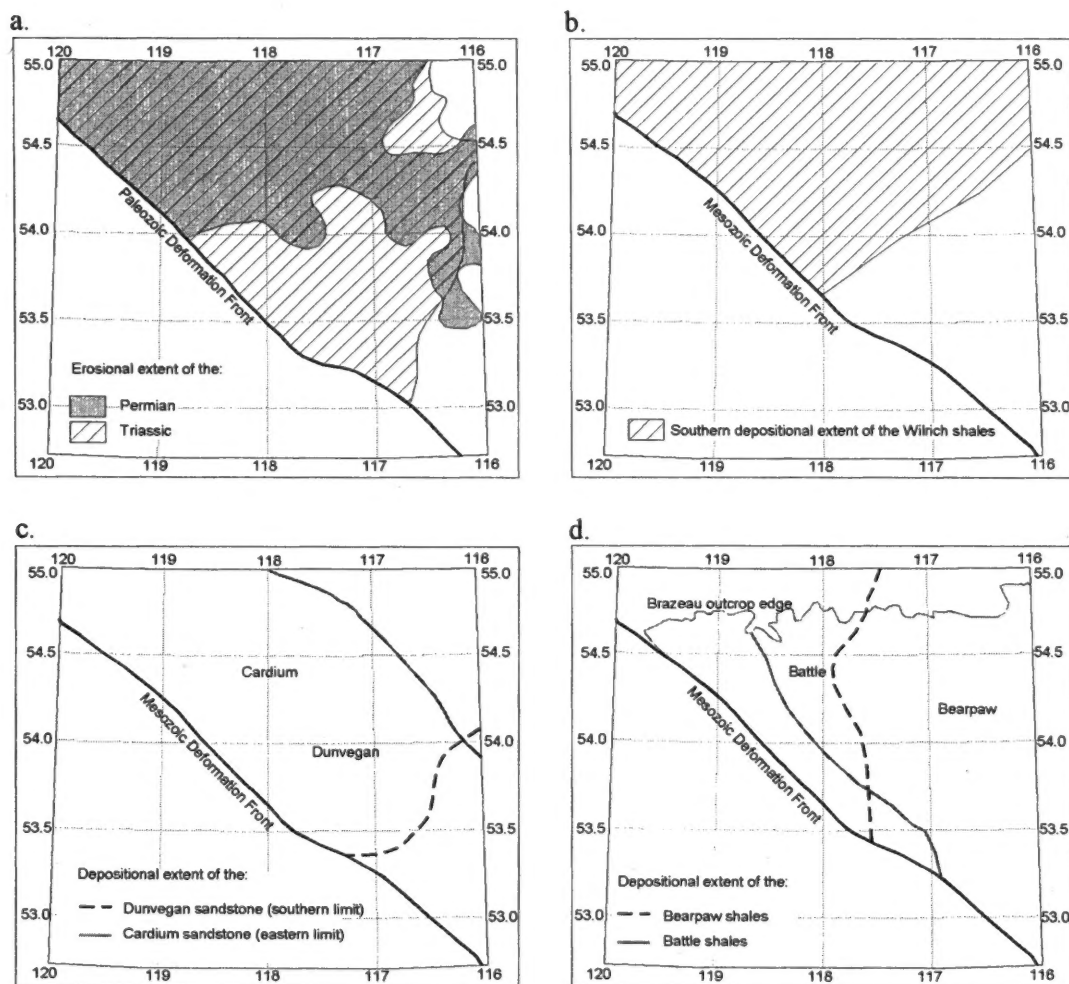


Figure 4.7: Boundaries of Late Paleozoic to Cretaceous strata in the study area: a) Permian and Triassic (Mossop & Shetsen, 1994), b) Wilrich shales (after Connolly, 1989), c) Cardium and Dunvegan sandstones (Mossop and Shetsen, 1994), and d) Bearpaw and Battle shales.

The Jurassic succession represents the transition from a passive to an active continental margin (Poulton, 1989). The main part of the Jurassic is formed by an assemblage of dominantly shales interbedded with thin sandstone layers of the Fernie Group. At the base of the Jurassic, a thin phosphatic siltstone layer is found, which becomes a limestone with chert lenses (Nordegg Mbr.) in the east of the study area (Poulton, 1989). The Fernie shales coarsen upward into sandstones of the Nikanassin Formation, which are late Jurassic to lower Cretaceous in age, and which are interbedded with thin coal seams. The entire succession is unconformably overlain by the Cretaceous Mannville Group.

4.4 Foreland basin succession (Late Jurassic – Recent)

With respect to global plate tectonics, the evolution of the Alberta Basin is closely related to the formation of the Cordillera (Price, 1994). Terrane accretion during the Columbian (Jurassic-Early Cretaceous) and Laramide (Mid-Late Cretaceous-Tertiary) orogenies controlled the sedimentation of the foreland succession (Porter et al., 1982).

The Mannville Group was deposited during the Columbian orogeny. The Lower Mannville Group is formed by dominantly fluvial sandstones and conglomerates grading upwards into delta and open marine sandstones and shales (Cant, 1989). Marine shales of the overlying Wilrich Formation thin out towards the southeast and the depositional facies changes to near-shore silt- and sandstones in the center of the study area, defining the boundary between Lower and Upper Mannville Groups (Fig. 4.7b). The Upper Mannville Group consists mainly of non-marine to marginal marine sandstone to shale units (Cant, 1989). Regionally extensive coal seams are found in both the Upper and the Lower Mannville Group (Smith et al., 1994).

The overlying Upper Cretaceous Colorado Group represents a thick wedge of marine shales with progradational packages of sandstones and conglomerate of different extent (Leckie, 1989), deposited during a lull in plate convergence and tectonic activity. Major

and regionally extensive sandstone units are Viking, Dunvegan, Cardium (Figs. 4.6 & 4.7c), and Badheart Formations. The shales continue at the top of the Colorado Group into the Lea Park Formation, which forms the boundary to the overlying Upper Cretaceous sediments of the Edmonton Group.

The overlying Upper Cretaceous to Tertiary succession was deposited during the Laramide orogeny. The Edmonton Group begins with an interval of clastic detritus of the mostly non-marine Brazeau and Wapiti Formations in the west, and with the Belly River Formation at the base in the east of the study area (Leckie, 1989). These formations successively crop out parallel to the northern boundary of the study area (Fig. 4.2). In the eastern part of the study area, the marine shales of the Bearpaw Formation (Fig. 4.7d) separate the underlying Belly River Formation from overlying terrestrial deposits of the Horseshoe Canyon Formation. The boundary with the coal-bearing strata of the Scollard Formation, better defined in the east by shales of the Battle Formation and the Kneehills Tuff Zone (Fig. 4.7d), is represented in the west by finer grained sandstones at the top of the Brazeau Formation. The youngest unit in the Edmonton Group is the Scollard Formation, which contains mostly clastic, alluvial plain deposits, shallow water and lake sediments, and regionally extensive coal seams up to 7 m thick (Smith, 1989). It crops out in the northern half of the study area (Fig. 4.2).

The Tertiary in the study area is represented by the Paskapoo Formation, the K/T - boundary itself being located in the underlying Scollard Formation. The deposits of the Paskapoo Formation are mostly sandstones and conglomerates, representing a continuing sedimentation of large alluvial fans. The deposition of Tertiary sediments lasted approximately to the peak of the Laramide orogeny (~53 Ma).

A major period of erosion, starting after the peak of the Laramide orogeny, has been responsible for shaping the basin relief until the present. Figure 4.8a shows that approximately 1.5 – 3.5 km of sediments were removed by erosion to the present-day bedrock topography (Magara, 1976b; Connolly, 1989; Bustin, 1991).

The thickness of the Quaternary cover in the study area ranges between approximately 0 and 120 m and consists mainly of glacial tills, and to a lesser degree of lacustrine and fluvial sediments (Fenton et al., 1994). At least five major southward advances of the Laurentide ice sheet in the plains region (Fenton, 1984) and four glaciations in the Canadian Cordillera (Fulton, 1984) are represented by the Pleistocene sediments. During its maximum advancement (~ 20 ka), the Laurentide ice sheet covered almost the entire study area (Fig. 4.8b) reaching a maximum thickness of 1 to 2 km (Matthews, 1974). An approximately 100 km wide, ice-free corridor might have existed during maximum Pleistocene glaciation between the Cordilleran and Laurentide glaciers in the southern part of the study area, sub-parallel to the deformation front (Rutter, 1984). The Laurentide ice-sheet had receded from the plains region about 7 ka ago, while the Cordilleran glacier cover reached a little more than its present extent by 10 ka (Fulton et al., 1984), allowing for the development of the current topography and drainage system.

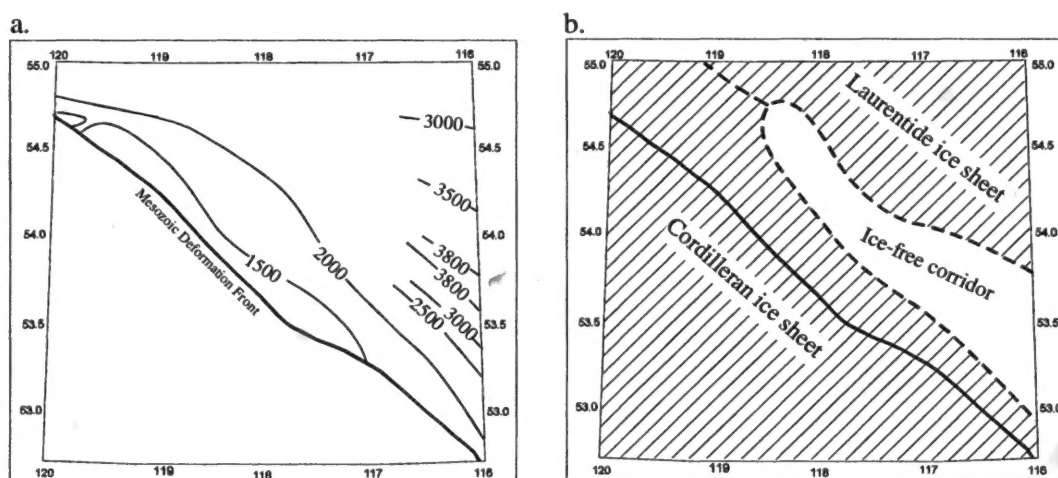


Figure 4.8: a) Schematic and generalized map of reconstructed thickness of overburden (in metres) in the study area (modified from Bustin, 1991), b) approximate maximum extent of the Cordilleran and Laurentide ice sheets during the Late Wisconsinan (modified from Fenton, 1984).

4.5 General hydrostratigraphy

A hydrostratigraphic framework was constructed by subdividing the entire stratigraphic succession into aquifers, aquitards and aquicludes (for definitions see Chapter 2, 2.3) based on the permeability inferred from the general lithology of the stratigraphic units (Fig. 4.4). Generally, coarse siliciclastics (gravels – sandstones) and carbonates were considered to be aquifers, whereas shales and evaporitic sequences form aquitards. The crystalline Precambrian basement was considered to be an aquiclude, but currently there are insufficient hydraulic data to definitively characterize it as such. The general subdivision of the stratigraphic succession into three hydrostratigraphic groups, each containing several aquifer and aquitard systems, is based on previous work in the west-central part of the Alberta Basin (Hitchon et al., 1990; Bachu 1995b). This hydrostratigraphic framework will be discussed in detail and individually for each hydrostratigraphic group in Chapters 5, 6, and 7, respectively.

CHAPTER 5: FLUID AND PRESSURE DISTRIBUTION IN THE FORELAND BASIN (TERTIARY-CRETACEOUS) SUCCESSION

5.1 Introduction

The post-Jurassic sedimentary succession in west-central Alberta is of special interest regarding its hydrogeology for the following reasons:

- 1) Severe underpressuring is observed in large parts of various Cretaceous aquifers, which has been attributed to the erosional rebound of thick intervening shale units (Bachu and Underschultz, 1995; Bachu, 1995a; Parks and Tóth, 1995). On the other hand, flow in shallower aquifers has adjusted to present-day ground surface topography. This study investigates the driving mechanisms for fluid flow in the succession, in an attempt to identify causes for abnormal fluid pressures, and examines to what extent the post-Jurassic succession has been flushed by meteoric water.
- 2) The deep part of the Cretaceous succession is mainly saturated with hydrocarbons (Fig. 5.1) and is referred to as the "deep basin gas trap" (Masters, 1979). The interaction between formation water flow and hydrocarbon generation and migration has been addressed so far in very few local-scale studies only (Pendergast, 1969; Putnam 1993; Putnam and Ward, 2001), and is further investigated in this study.

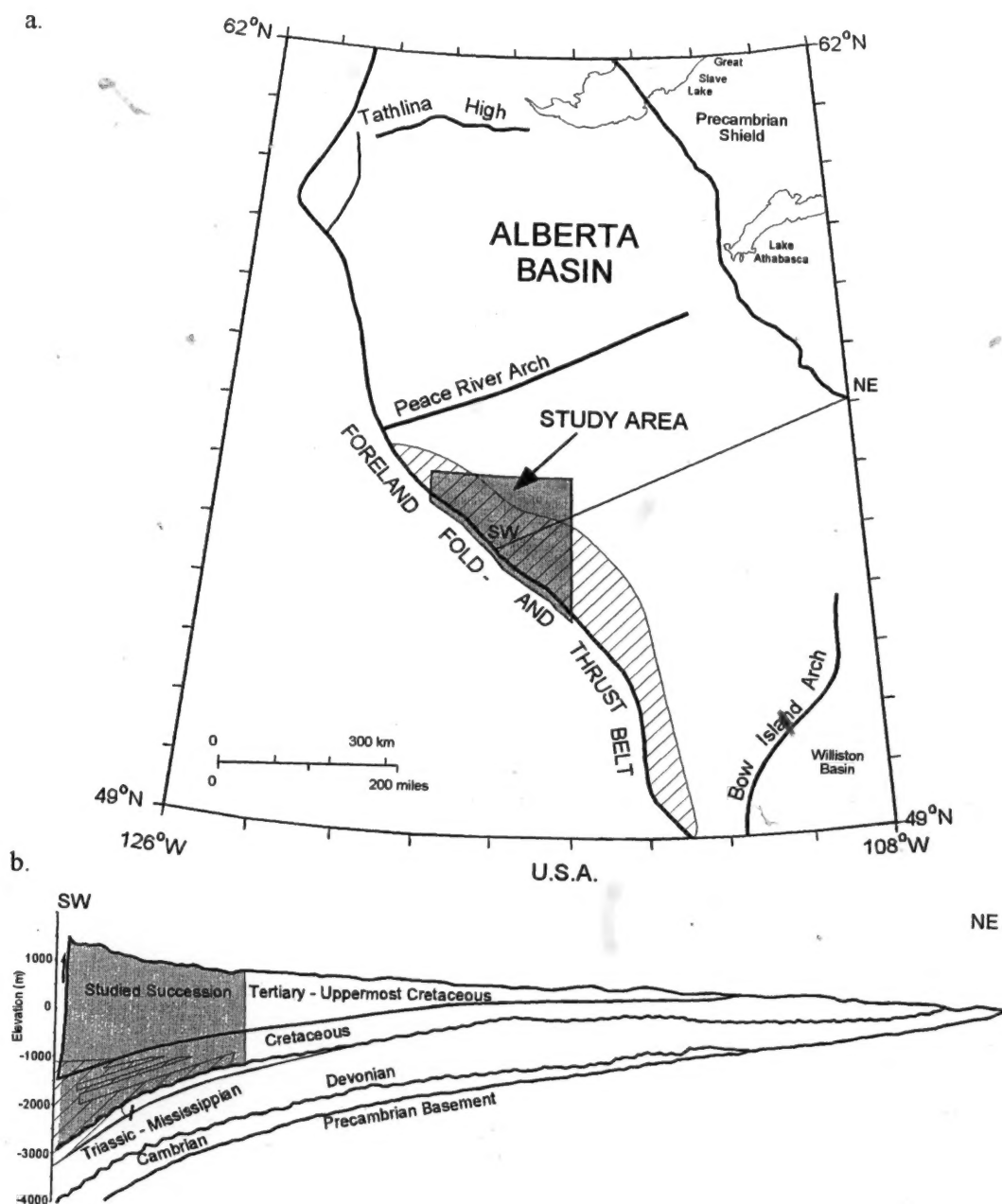


Figure 5.1: Location of the study area in the Alberta Basin: a) in plan view, and b) stratigraphically along a dip cross section. The hatched area represents the approximate extent of the gas-saturated "deep basin" (after Masters, 1984).

- 3) The question of hydraulic communication between flow in the thrust and fold belt and flow in the plains region is still not satisfactorily answered, as different interpretations exist for various areas along the deformation front. Recharge of the Cretaceous Mannville aquifer by meteoric water from the thrust and fold belt was identified in the northern part of the Peace River region (Thompson, 1989), north of the study area, consistent with basin-scale recharge from the thrust and fold belt in the northern part of the Alberta Basin (Bachu, 1997). In the southern part of the Peace River region flow appears to be hindered by the "deep basin" gas accumulations that act as barrier to fluid flow (Thompson, 1989). Lack of hydraulic communication between the deformed and undeformed parts of the Alberta Basin was inferred also south of the Peace River region based on flow patterns (Bachu, 1995a, 1999).

Answering the above questions may help to better understand the basin-scale flow patterns and their driving mechanisms in the Alberta Basin as a whole, and to identify fluid origins. Understanding the interaction between hydrocarbon- and water-saturated regions is of particular interest because the Cretaceous succession is a major target for petroleum exploration and exploitation in this part of the basin, and the flow of formation waters has affected and still influences to a large extent the migration and accumulation of hydrocarbons.

5.2 Hydrostratigraphic framework

The Tertiary-Cretaceous sedimentary succession consists of fluvio-deltaic and marine to marginal marine siliciclastics (Smith, 1994). The Jurassic Fernie shales form a regional extensive aquitard (Bachu, 1995a) and represent the base of this hydrostratigraphic group (Fig. 5.2), which can be divided into three major hydrostratigraphic systems: I) the post-Colorado aquifer system, II) the Colorado aquitard system, and III) the Mannville aquifer system. Herein, sandstone dominated formations form aquifers, whereas shale formations act as aquitards. The hydrogeology of the three hydrostratigraphic systems will be discussed in descending stratigraphic order.

Period	Group / Formation	Lithology	Thickness	Hydrostratigraphy	Syst.
Tertiary	Paskapoo		0 - 700 m	Scollard - Paskapoo	
	Edmonton Gp.		100 - 500 m		
Cretaceous	Brazeau		600 - 1500 m		I
	Scollard				
	Battle				
	Whitemud				
	Horseshoe C.				
	Bearpaw		0 - 100 m		
	Belly River		250 - 300 m		
	Lea Park / Chinook		0 - 25 m	Chinook	
	Colorado Gp.		5 - 40 m	Badheart	
	Cardium		0 - 80 m	Cardium	
	Dunvegan		0 - 240 m	Dunvegan	II
	Paddy - Viking		5 - 50 m	Viking	
	Cadotte / Joli		5 - 20 m		
	Harmon / Fou				
Jurassic	Mannville Gp.		0 - 120 m	Upper Mannville	III
	Wilrich				
	Lower Mannville		200 - 800 m	Lower Mannville	
	Nikanassin				
	Fernie Gp.		20 - 120 m		

 Sandstone
  Shale
  Aquitard
  Aquifer

Figure 5.2: General lithology and hydrostratigraphy of the Tertiary-Cretaceous succession in the study area.

Post-Colorado aquifer system

The post-Colorado aquifers crop out underneath the Quaternary cover, where these aquifers are replenished by meteoric water, and discharge at the valleys of the Athabasca and Smoky Rivers and their tributaries (Fig. 5.3) that cut into the unconsolidated Quaternary sedimentary cover and the top of the bedrock (Barnes, 1977; Tokarsky, 1997; see Chapter 4, Fig. 4.2). Based on the general lithology distribution, the post-Colorado represents a relatively continuous aquifer system from the ground surface down to the

Lea Park shales, the latter defining the lower boundary. Regional-scale aquitards are the shales of the Battle Formation and the Bearpaw Formation, which are both absent in parts of the study area (see Chapter 4, Fig. 4.7 d). The western depositional edge of the Battle aquitard runs at some 25 km distance sub-parallel to the deformation front, such that the Brazeau aquifer is in direct contact with the overlying Scollard-Paskapoo aquifer. The Bearpaw Formation is deposited only in the eastern part of the study area, and its thickness reaches up to 100 m. Here the Bearpaw aquitard subdivides the Brazeau-Belly River aquifer into the Belly River and Horseshoe Canyon aquifers.

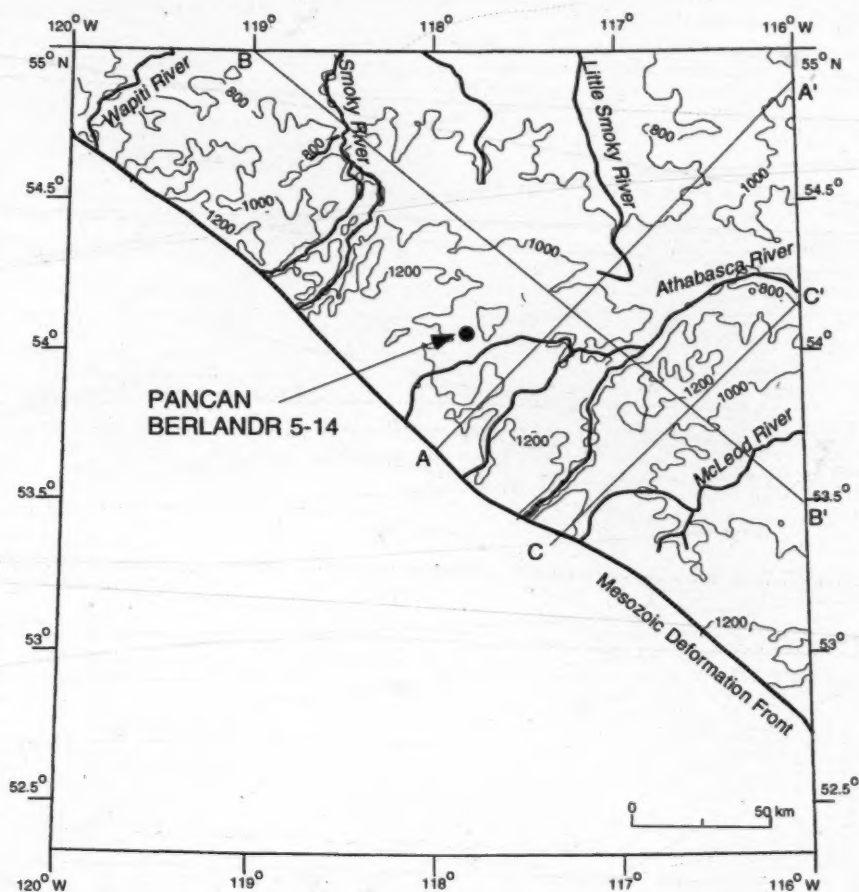


Figure 5.3: Topographic map of the study area showing lines of cross sections and location of a PanCan well (s. Fig. 5.33).

Colorado aquifer-aquitard system

The lithology of the Colorado aquitard system is dominated by the up to 1500 m thick Colorado Group shales, which represent a major continuous aquitard system throughout the Alberta Basin (Bachu, 1995a). Five embedded sandstone units form isolated aquifers: Chinook, Badheart, Cardium, Dunvegan, and Viking. The Viking aquifer at the base of the system is separated from the underlying Mannville aquifer system by the relatively thin Joli Fou aquitard.

Mannville aquifer system

The Mannville aquifer system is subdivided by the Wilrich aquitard into the Upper and Lower Mannville aquifers in the northwestern half of the study area, where the former is present (see Chapter 4, Fig. 4.7 b). Along the Rocky Mountain Foothills, the Mannville sandstones directly overlie the sandstones of the Jurassic – Lower Cretaceous Nikanassin Formation, thus forming a single hydrostratigraphic unit that will be referred to as the Lower Mannville aquifer. The underlying continuous shales of the Jurassic Fernie Group represent the lower boundary of the Mannville aquifer system.

5.3 Hydrogeological patterns

Contour maps of equivalent freshwater hydraulic heads (reference density $\rho_0 = 1000 \text{ kg/m}^3$), as well as $p(d)$ - and $p(z)$ -plots were used to interpret the flow in the foreland-basin succession. Only pressure data from DSTs in which water was dominantly recovered were used to calculate hydraulic heads and contoured. Water, gas and oil pressure data are presented in the $p(d)$ - and $p(z)$ -plots. The DFR in the studied aquifers is everywhere < 0.35 due to a combination of: a) relatively low salinity, b) strong hydraulic gradients, and c) location of the water-saturated zones in the shallower part of the study

area, where the aquifer slope is relatively mild ($< 8\text{m/km}$). The small DFR indicates that the errors in flow representation are small, and therefore the use of freshwater hydraulic heads in interpreting the flow is justified (s. Chapter 2). Hydrogeochemical data are presented in the form of contour maps of salinity and bicarbonate concentrations to supplement the pressure data, and to identify fluid sources and pathways.

The aquifers were subdivided into water-saturated and hydrocarbon-saturated zones, I and II, respectively. Hydrostatic-to-subhydrostatic pressures (subzone Ia) and underpressures (subzone Ib) can be distinguished in the water-saturated zone. The boundary between these subzones was obtained by mapping pressure data that plot along different, offset lines in the $p(z)$ -plot, indicating some sort of permeability barrier or transmissivity change between the two pressure populations (see Chapter 2, 2.3). The hydrocarbon-saturated zone in some aquifers could be further subdivided into underpressured gas (or overpressured oil in the Cardium), being located directly downdip of the underpressured water-saturated zone. Gas and oil pressures from the hydrocarbon-saturated zones plot along various lines with static gas and oil gradient, respectively. This hydrocarbon-saturated subzone is respectively denoted as IIa or IIb, depending on whether or not it is adjacent in turn to a normally-to-overpressured subzone IIc further downdip. The zonation of the various aquifers and the range of the hydrogeological data in the water-saturated zone are summarized in Table 5.1.

Unit	Zone	Subzone	Fluid	Pressure Regime	H _f (m)	TDS (g/L)
Scollard-Paskapoo			Water	(sub-)hydrostatic		
Brazeau-Belly River	I	a	Water	(sub-)hydrostatic	625 - 825	1.7 - 10.5
		b	Water	Underpressured	500 - 625	
	II		Oil	Underpressured		
Cardium	I	a	Water	(sub-)hydrostatic	350 - 500	15 - 26
		b	Water	Underpressured	700 - 800	7 - 14
	II	a	Oil	Overpressured		
		b	Oil	Overpressured		
		c	Gas	Normally-pressured		
Dunvegan	I	a	Water	(sub-)hydrostatic	450 - 550	7 - 13
		b	Water	Underpressured	200 - 400	
	II		Gas	Normally-pressured		
Viking	I	a	Water	(sub-)hydrostatic	500	10 - 25
		b	Water	Underpressured	350 - 500	
	II	a	Gas	Underpressured		
		b	Gas	Underpressured		
		c	Gas	Over- and Normally-pressured		
Upper Mannville	I	a	Water	(sub-)hydrostatic	550 - 700	9 - 36
		b	Water	Underpressured	300 - 500	
	II	a	Gas	Underpressured		
		b	Gas	Underpressured		
		c	Gas	Over- and Normally-pressured		
Lower Mannville	I	Ia	Water	(sub-)hydrostatic	500 - 650	35 - 90
		Ib	Water	Underpressured	350 - 500	
	II	IIa	Gas	Underpressured		
		IIb	Gas	Underpressured		
		IIc	Gas	Over- and Normally-pressured		

Table 5.1: Summary of fluid distribution, pressure regimes and ranges in hydraulic heads and salinity in the post-Jurassic aquifers in the study area.

Post-Colorado aquifer system

The hydrogeological data in the Scollard – Paskapoo aquifers are relatively sparse and cannot be contoured areally. Therefore, flow is only interpreted along selected cross sections, and the pressure data are compared to the ground surface and to data from the directly underlying Brazeau-Belly River aquifer. Figures 5.4 to 5.7 present, respectively, the distribution of freshwater hydraulic heads, $p(d)$ - and $p(z)$ -plots, and distributions of salinity and bicarbonate in the Brazeau-Belly River aquifer.

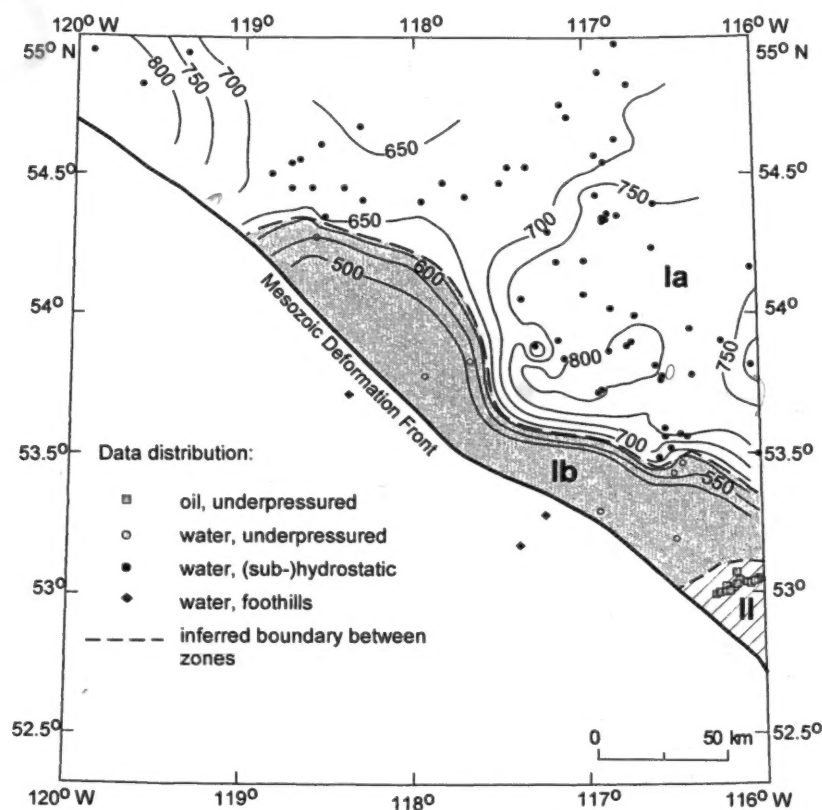


Figure 5.4: Freshwater hydraulic head distribution and aquifer zonation in the Brazeau-Belly River aquifer (50 m contour interval). For better visualization purposes, subzone Ib is shaded grey and the hydrocarbon-saturated zone II is hashed.

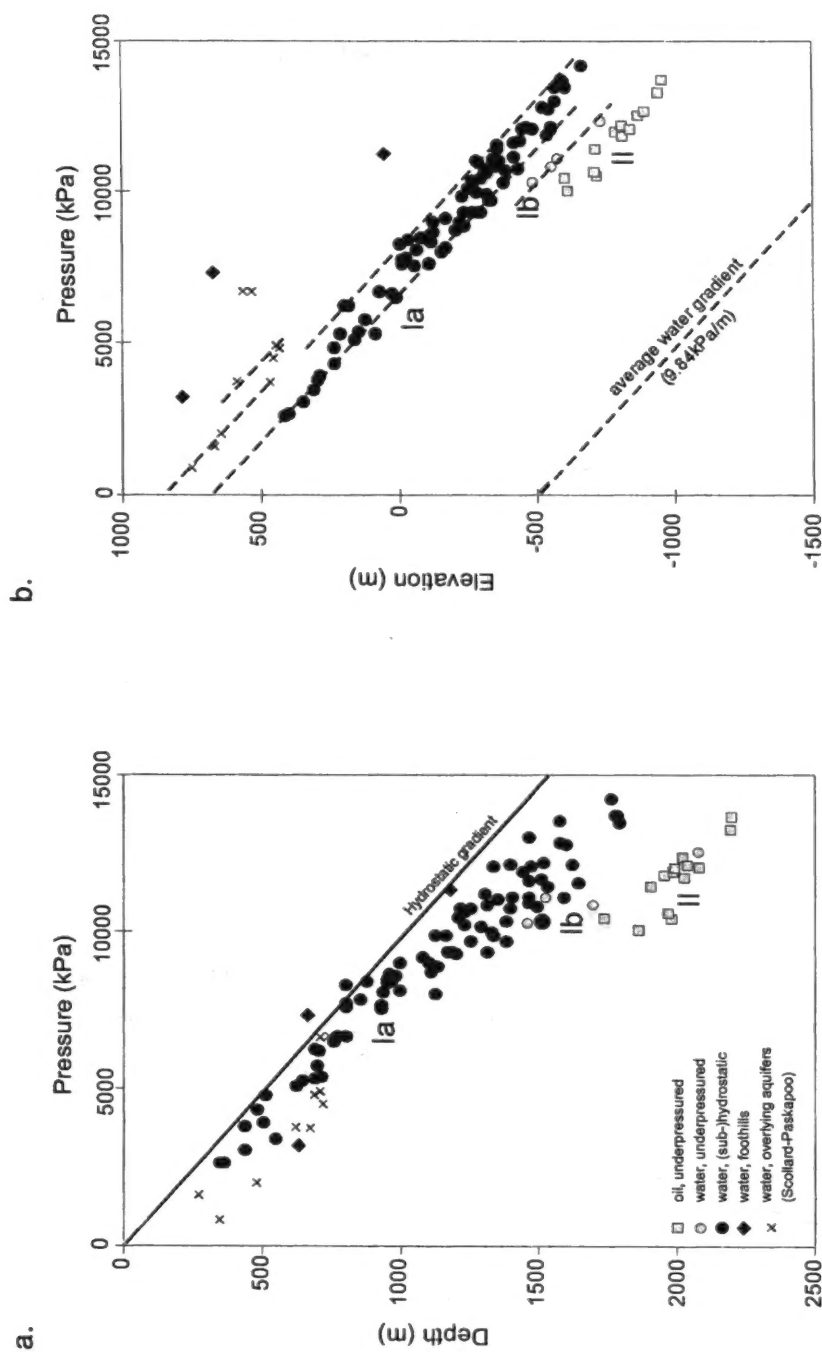


Figure 5.5: Pressure variation with: a) depth and b) elevation, in the post-Colorado aquifers (Brazeau-Belly River and Scollard-Paskapoo). The data groups denoted by roman numbers correspond to the geographic distributions shown in Figure 5.4.

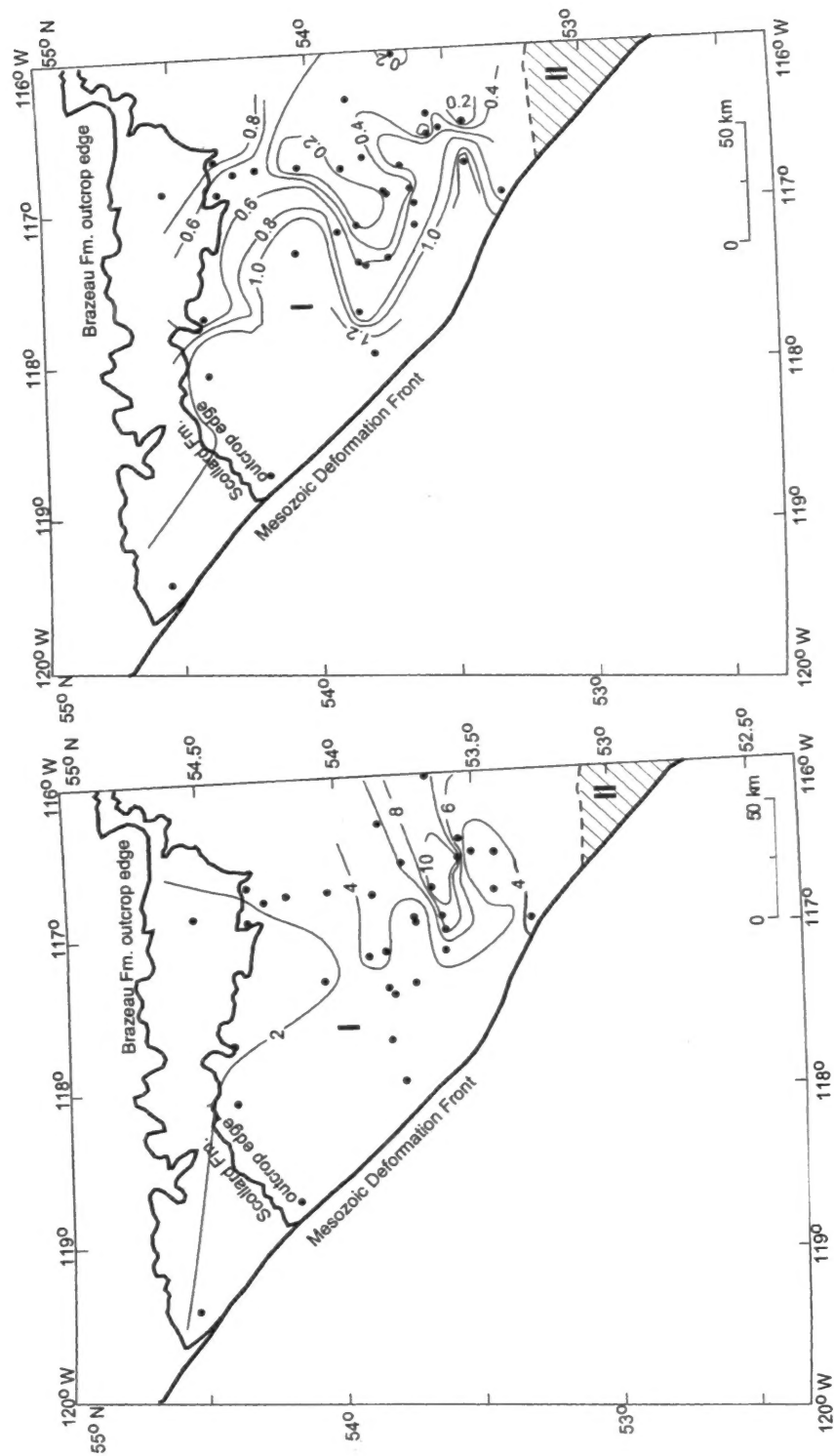


Figure 5.6: Salinity distribution in the Brazeau-Belly River aquifer (2 g/l contour interval). Zones I and II correspond to the zonation in Figure 5.4.

Figure 5.7: Bicarbonate distribution in the Brazeau-Belly River aquifer (0.2 g/l contour interval). Zones I and II correspond to the zonation in Figure 5.4.

Pressure data from the Brazeau-Belly River are mainly from depths close to the Lea Park shales and can be divided into two groups: I) data where the DST recovery was dominantly water and II) data with oil but almost no water recovered. The two groups distribute areally into two corresponding zones (Fig. 5.4). Freshwater hydraulic heads in the larger part of the water-saturated zone (Ia) of the aquifer range between approximately 650 and 830 m. The general inferred flow direction is from two areas: a topographic high at 53.8° N and 116.8° W, and in the northwestern corner of the study area (Fig. 5.3), towards the Smoky and Little Smoky river valleys at the northern boundary. An area with very low hydraulic heads (less than 600 m in subzone Ib) is situated in the deep parts of the Brazeau-Belly River aquifer, sub-parallel to the deformation front. Relatively steep hydraulic gradients along the boundary between aquifer zones Ia and Ib are in opposite direction to the regional ground surface slope, and therefore suggest the potential for inward flow towards the foothills region.

On the p(d)-plot (Fig. 5.5a) almost all data points plot below hydrostatic, becoming increasingly underpressured with depth, which indicates a general downward direction of fluid flow. Pressure data from DSTs with oil as the dominant fluid phase plot separately, and show significant underpressuring. The oil pressure data plot approximately along the static oil gradient (Fig. 5.5b). Extrapolating this gradient to the line that represents the water gradient in subzone Ia suggest a regional oil – water contact at -500 m elevation. Hydraulic heads drop from the ground surface to the Scollard-Paskapoo aquifer, and even farther in the Brazeau-Belly River aquifer (Fig. 5.5b), indicating the potential for downward flow, and that the intervening major aquitards (Battle and Bearpaw) and other minor and localized, but frequent shaly aquitards provide a significant resistance to flow. Hence, the Brazeau-Belly River presents the characteristics of an aquifer confined by leaky and tight aquitards at the top and bottom, respectively.

The concentration of total dissolved solids (TDS) ranges between 1.7 and 10 g/L (Fig. 5.6). The salinity is lowest in the discharge region in the area of Brazeau outcrop, where the main aquitards, Battle and Bearpaw, are thin or absent, and deep formation waters can mix with shallow, meteoric groundwater. The value of 1.7 g/L is still relatively high

compared to the salinity usually observed in shallow aquifers (~ 0.5 g/L). The discharge of the more saline formation water from the deep parts of the Brazeau-Belly River aquifer causes an increase in salinity in shallow aquifers in that region (Barnes, 1987; Tokarsky, 1977). Salinity increases with depth, and a plume of maximum TDS values up to 10 g/L can be observed in the region at 53.8° N and 116.8° W, which corresponds to high ground surface elevation (Fig. 5.3) and high hydraulic heads (Fig. 5.4).

The distribution of bicarbonate concentrations (Fig. 5.7) complements the TDS map. The main bicarbonate input in shallow groundwater systems comes from dissolved carbon dioxide from the air, and dissolution of carbonate mineral (Freeze and Cherry, 1979; p. 241-243). The concentration decreases with increasing residence time of the formation water due to adsorption processes and flushing from the active flow zone (Freeze and Cherry, 1979). Bicarbonate values in the study area are highest in the region of shallow groundwater influence in the northeast and along the foothills.

Colorado aquifers

The flow in the Chinook and Badheart aquifers could not be analyzed and interpreted because of the lack of data. Figures 5.8 to 5.11 present, respectively, the distribution of freshwater hydraulic heads, $p(d)$ - and $p(z)$ -plots, and distributions of salinity and bicarbonate in the Cardium aquifer.

Hydraulic heads in the 700 – 800 m range in subzone Ia in the Cardium aquifer (Fig. 5.8) correspond to the elevation of the Cardium Formation outcrop some 50 km north of the study area to which this part of the aquifer appears to be hydraulically connected. Pressures are hydrostatic in the northern, shallow part of subzone Ia and develop into sub-hydrostatic pressures with increasing depth (Fig. 5.9 a) and towards the southeast. Hydraulic heads in the 350 – 500 m range in subzone Ib are significantly lower than the heads in subzone Ia (Fig. 5.8), and the corresponding pressures plot along a separate, underpressured gradient (Fig. 5.9 b). The dominantly hydrocarbon-saturated zone II in

the Cardium aquifer can be subdivided into an oil- and a gas-saturated subzone, IIa & b and IIc, respectively. The pressures in these subzones, although similarly located downdip of the water-saturated zones as in the Brazeau-Belly River aquifer, fall approximately on the hydrostatic gradient (subzones IIc) or plot above hydrostatic (subzone IIa & b) (Fig. 5.9).

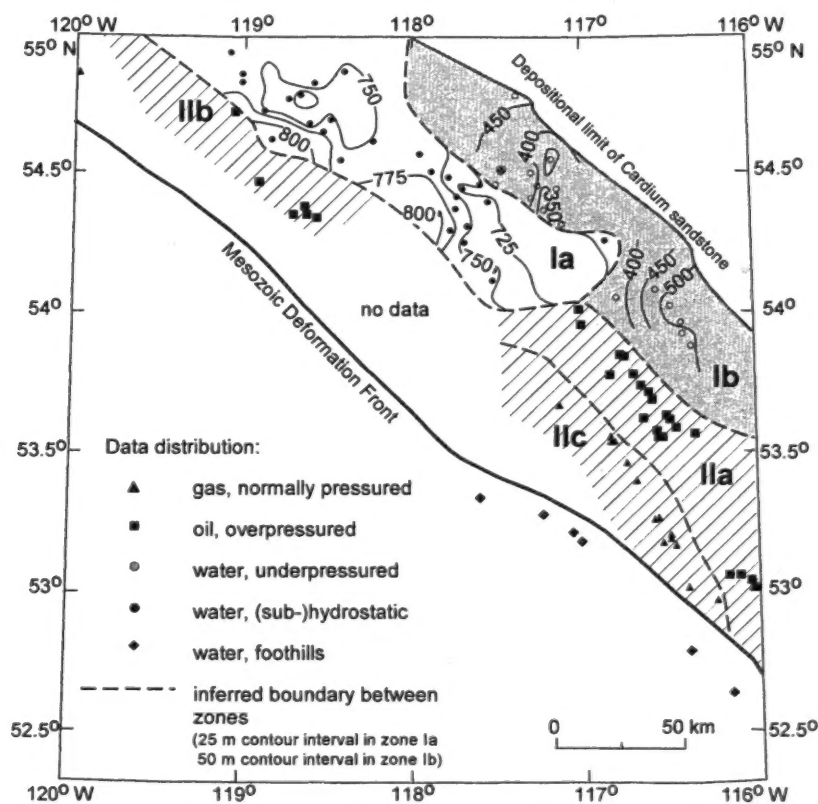


Figure 5.8: Freshwater hydraulic head distribution and aquifer zonation in the Cardium aquifer (note the different contour intervals).

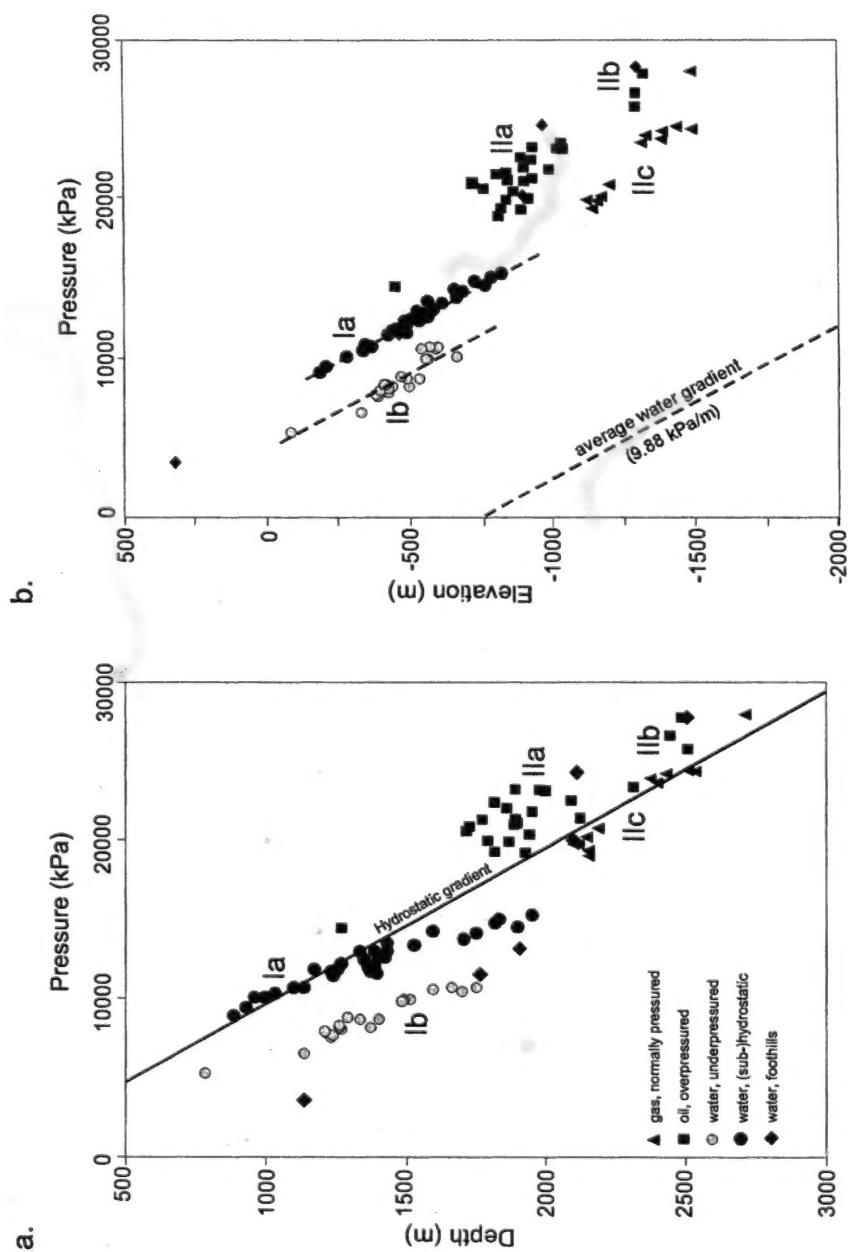


Figure 5.9: Pressure variation with: a) depth and b) elevation in the Cardium aquifer. The data groups denoted by roman numbers correspond to the geographic distributions shown in Figure 5.8.

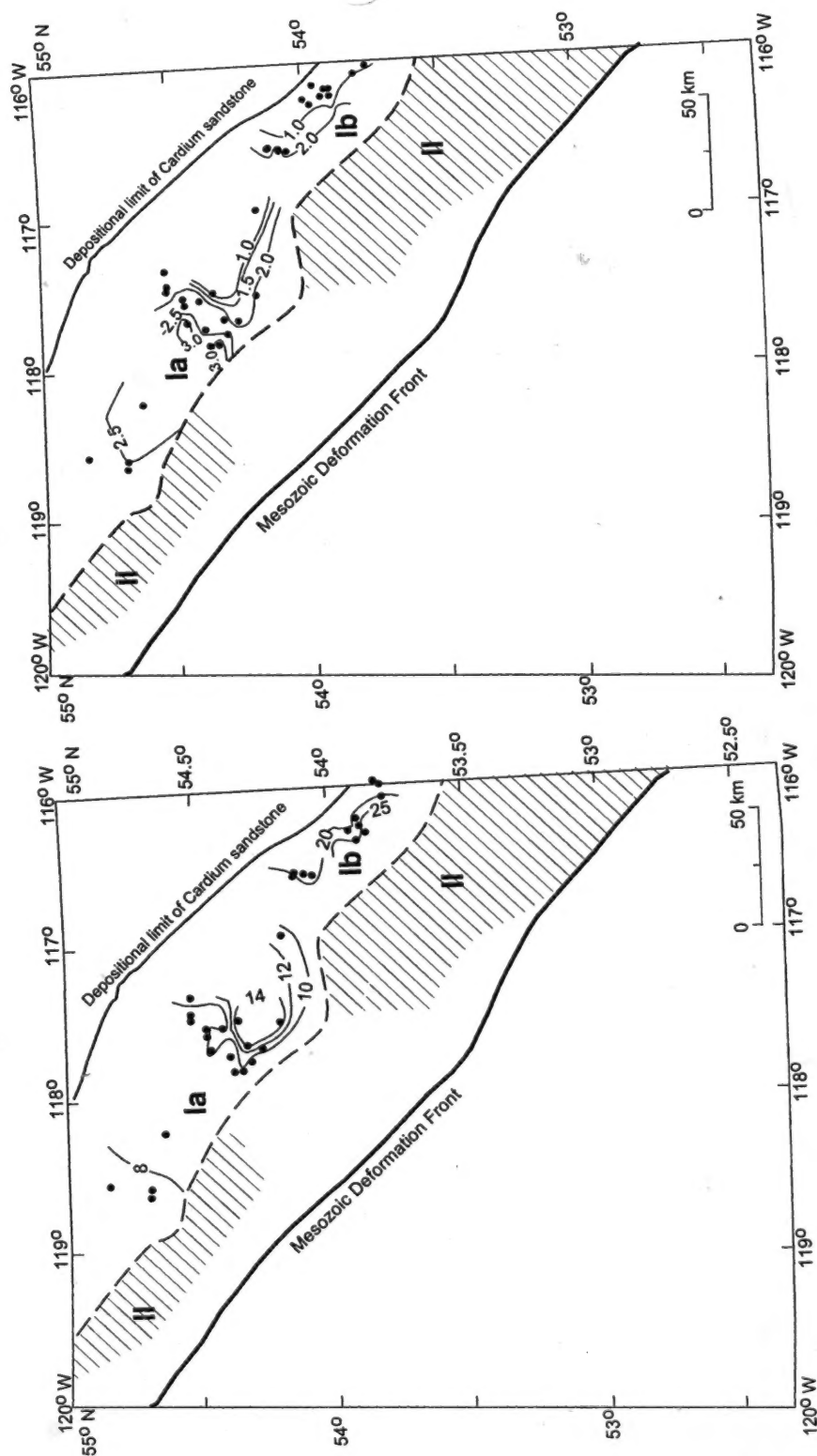


Figure 5.10: Salinity distribution in the Cardium aquifer (note the different contour intervals). (Sub-)zones Ia, Ib and II correspond to the zonation in Figure 5.8.

Figure 5.11: Bicarbonate distribution in the Cardium aquifer (0.5 g/l contour interval). (Sub-)zones Ia, Ib and II correspond to the zonation in Figure 5.8.

The salinity of formation waters in subzone Ia increases from 7 g/L to approximately 14 g/L (Fig. 5.10) in the direction of southeastward decreasing hydraulic heads (Fig. 5.8). Higher salinities in subzone Ib, in the 20 – 25 g/L range, suggest that this part of the aquifer is largely cut off from meteoric recharge. This is supported by the slightly higher range in bicarbonate concentrations (1 – 3 g/L) in subzone Ia compared to 1 – 2 g/L in subzone Ib (Fig. 5.11).

Figures 5.12 to 5.15 present, respectively, the distribution of freshwater hydraulic heads, p(d)- and p(z)-plots, and the distributions of salinity and bicarbonate in the Dunvegan aquifer. Hydraulic heads in subzone Ia show only a small variation between 500 and 550 m (Fig. 5.12) so that flow directions cannot easily be established. The Dunvegan aquifer crops out at elevations of 455 to 610 m along the Peace River some 100 km north of the study area and, therefore, a hydraulic connection of subzone Ia to the ground surface seems likely. Pressures (Fig. 5.13) and hydraulic heads in subzone Ib are significantly lower and appear to be isolated from other aquifer zones, as well as from the ground surface. Zone II in the deeper parts of the Dunvegan aquifer is dominantly gas-saturated, with slightly sub- to slightly above-hydrostatic pressures (Fig. 5.13). The salinity in the water-saturated zone is in the range of 7 to 13 g/L (Fig. 5.14) and bicarbonate concentration ranges between 0.9 to 2.8 g/L (Fig. 5.15), but data are too scarce to construct meaningful contour maps.

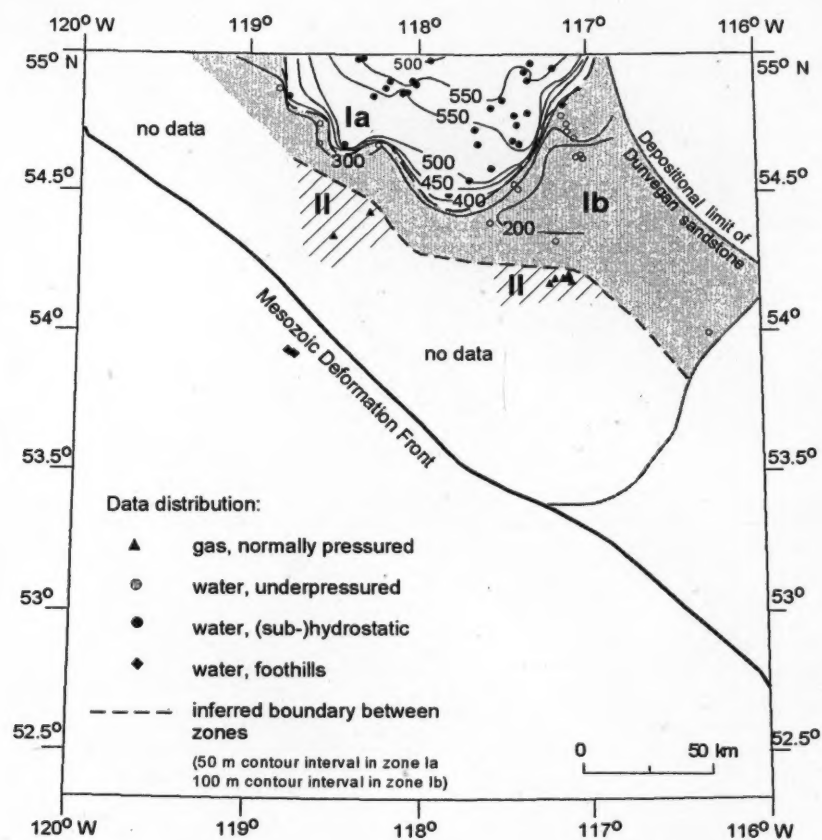


Figure 5.12: Freshwater hydraulic head distribution and aquifer zonation in the Dunvegan aquifer (note the different contour intervals).

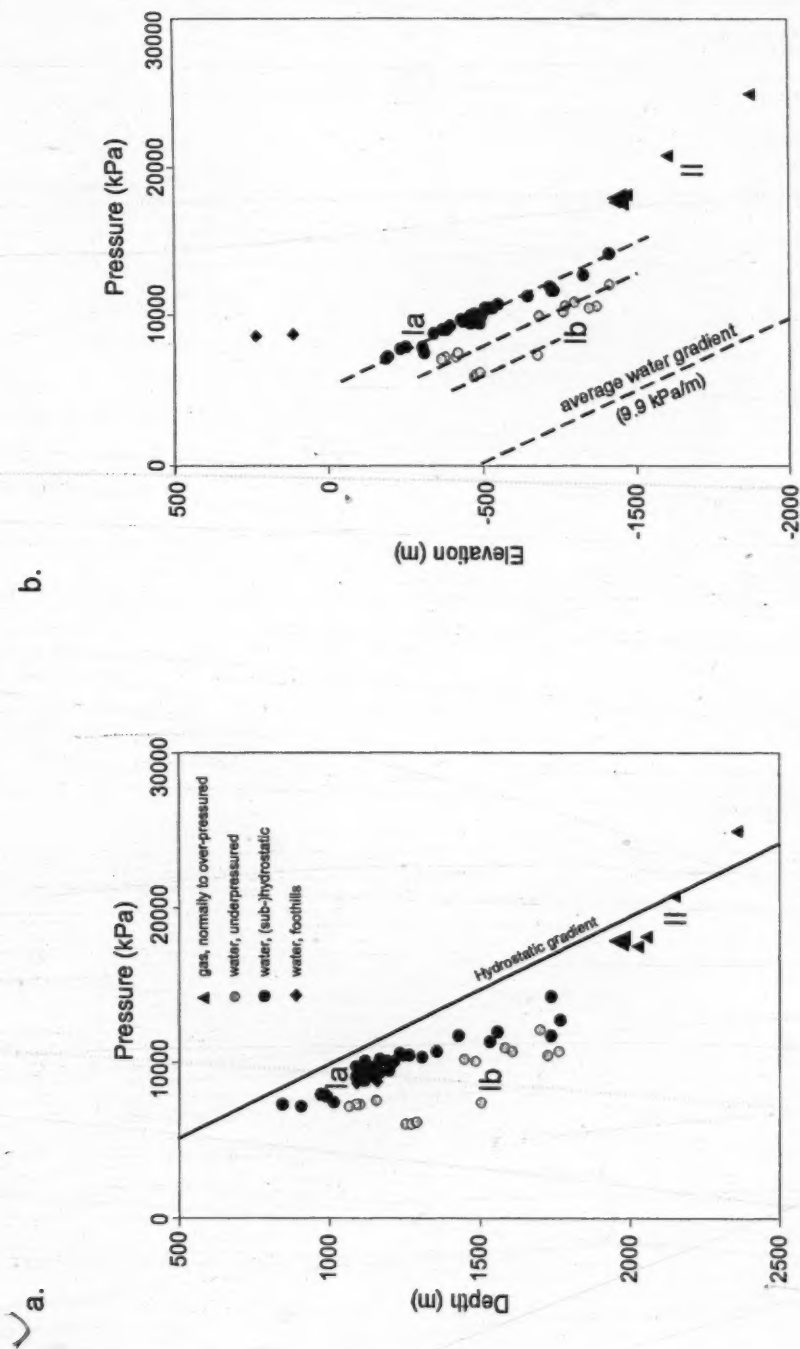


Figure 5.13: Pressure variation with: a) depth and b) elevation in the Dunvegan aquifer. The data groups denoted by roman numbers correspond to the geographic distributions shown in Figure 5.12.

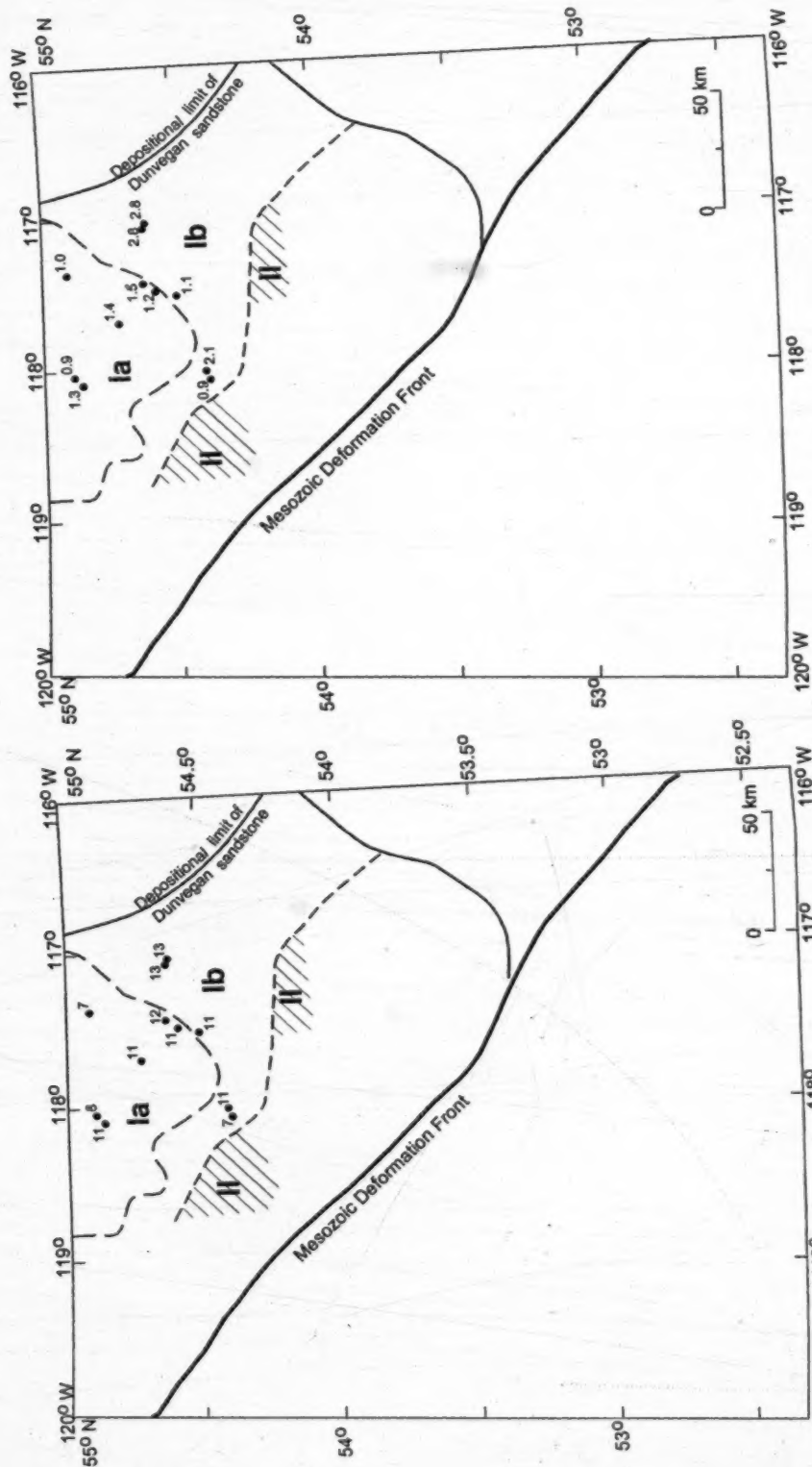


Figure 5.14: Salinity distribution in the Dunvegan aquifer (point values in g/l). (Sub-)zones Ia, Ib and II correspond to the zonation in Figure 5.12.

Figure 5.15: Bicarbonate distribution in the Dunvegan aquifer (point values in g/l). (Sub-)zones Ia, Ib and II correspond to the zonation in Figure 5.12.

Figures 5.16 to 5.19 present, respectively, the distribution of freshwater hydraulic heads, p(d)- and p(z)-plots, and distributions of salinity and bicarbonate in the Viking aquifer. Hydraulic heads (Fig. 5.16) are also in the 500 m and 300 to 450 m range in subzones Ia and Ib, respectively, like in the overlying Dunvegan aquifer, but the respective subzones in both aquifers do not overlap. The change in the hydraulic gradient and the difference between the sub-hydrostatically pressured (Ia) and underpressured (Ib) subzones (Figs. 5.16 & 5.17) are not as sharp as the changes in the Cardium and Dunvegan aquifers.

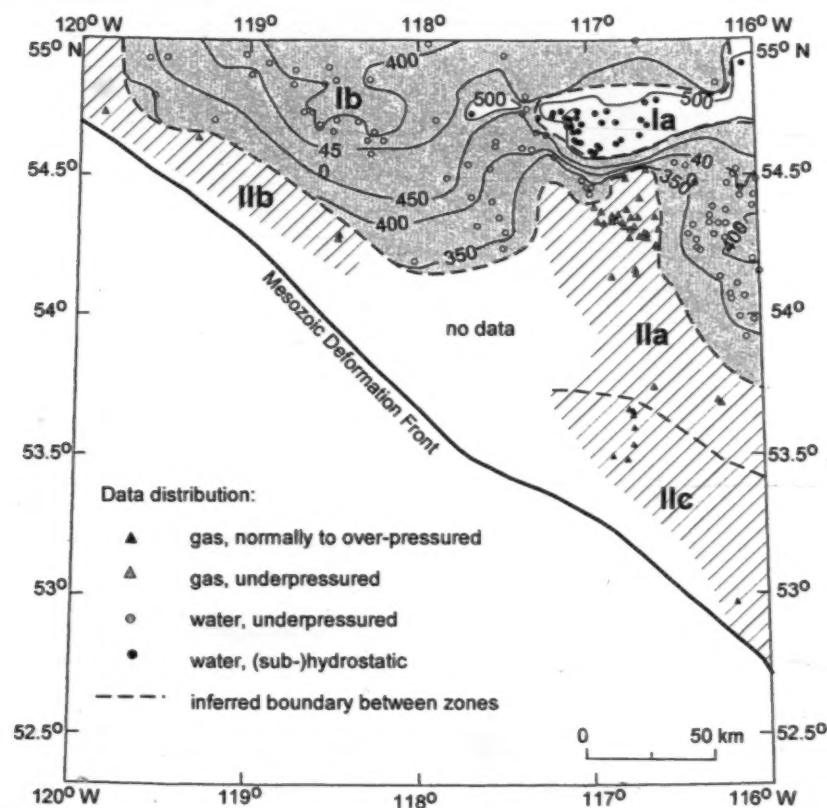
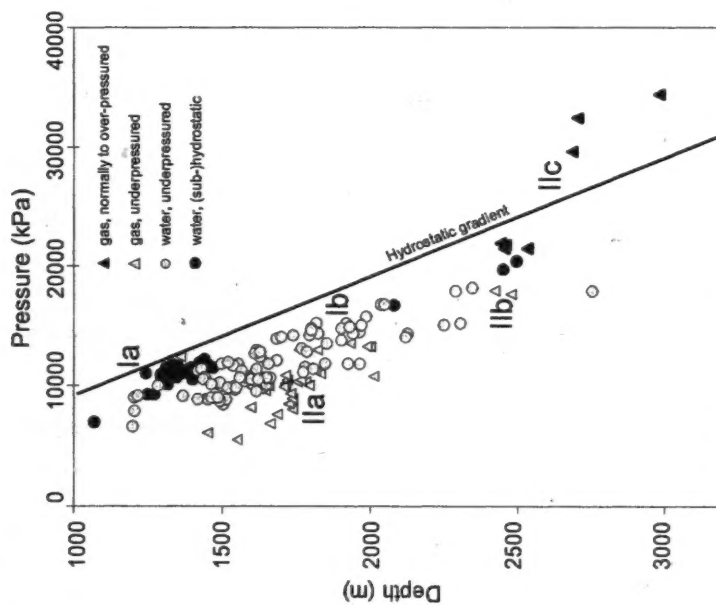


Figure 5.16: Freshwater hydraulic head distribution and aquifer zonation in the Viking aquifer (50 m contour interval).

a.



b.

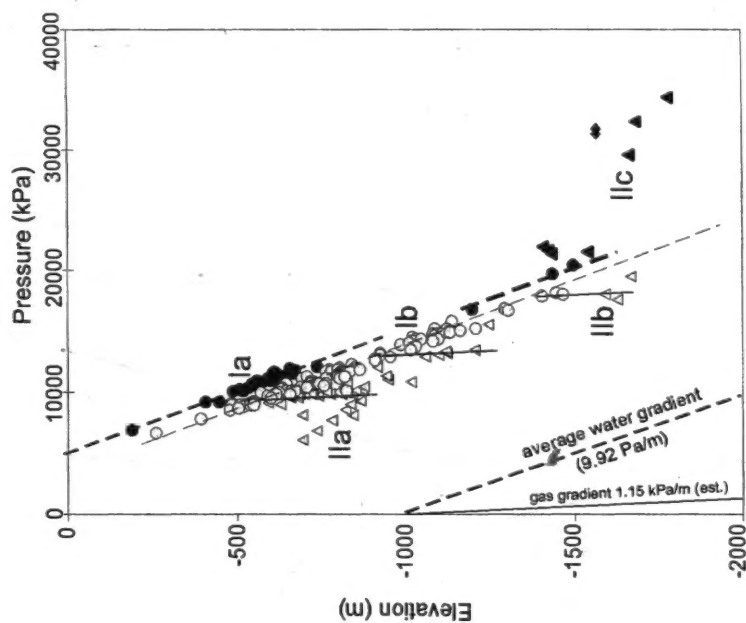


Figure 5.17: Pressure variation with: a) depth and b) elevation in the Viking aquifer. The data groups denoted by roman numbers correspond to the geographic distributions shown in Figure 5.16.

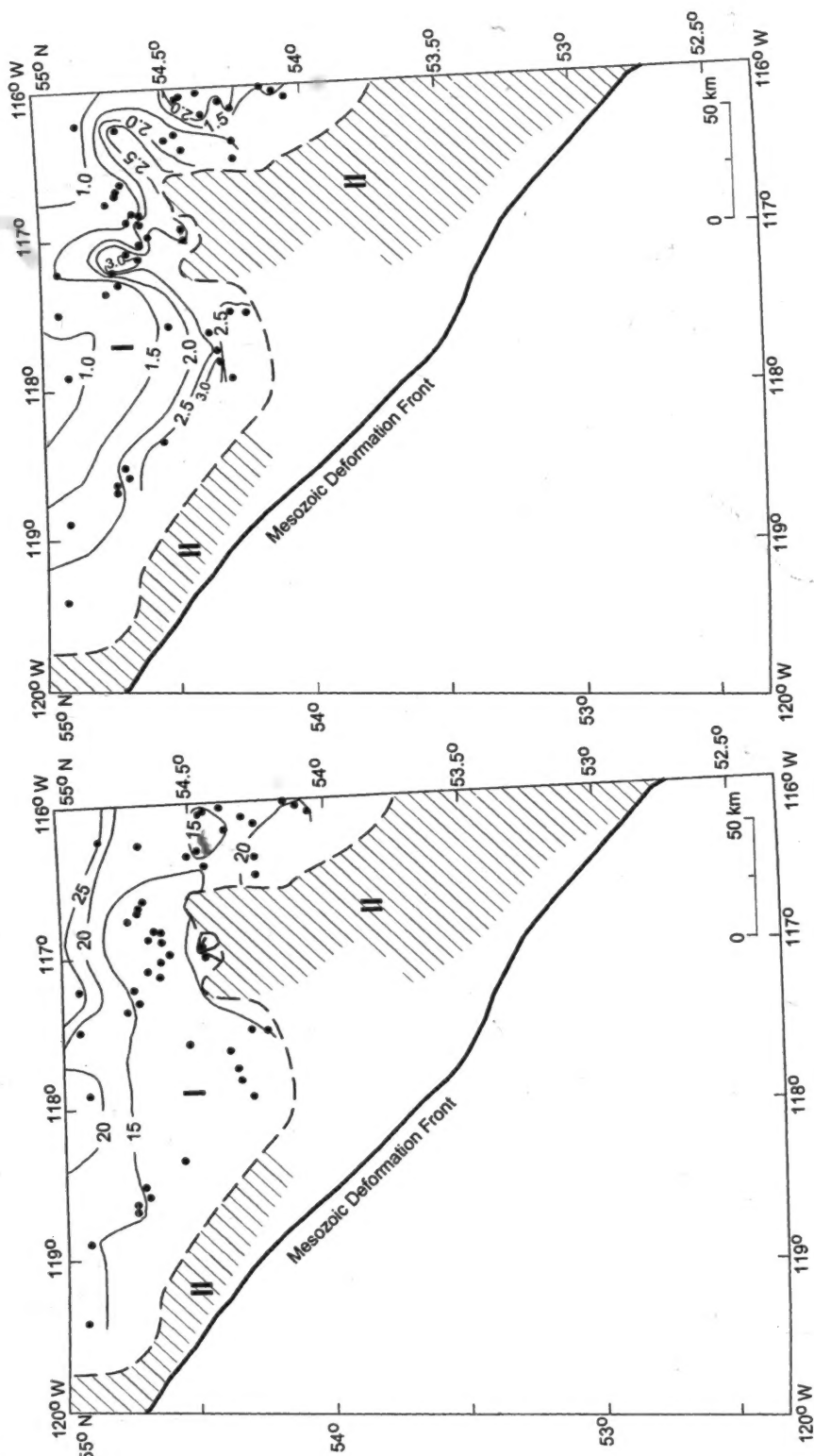


Figure 5.18: Salinity distribution in the Viking aquifer (5 g/l contour interval). Zones I and II correspond to the zonation in Figure 5.16.

Figure 5.19: Bicarbonate distribution in the Viking aquifer (0.5 g/l contour interval). Zones I and II correspond to the zonation in Figure 5.16.

Maximum hydraulic heads in the Viking aquifer (~500 m) can be observed in subzone Ia, which appears to be rather isolated, except for a possible continuation of this subzone beyond the northeast corner of the study area (Fig. 5.16). Hence, the flow in subzone Ia may be either laterally from or to the northeast, or vertical from over- or underlying aquifers. The gas-saturated zone in the deep parts of the Viking can be further subdivided into subzones IIa & b and IIc, with sub-hydrostatic and slightly sub-hydrostatic to above-hydrostatic pressures, respectively (Fig. 5.16 & 5.17). Pressures in subzones IIa & b plot approximately along a static gas gradient, suggesting that this zone represents an unconventional gas accumulation downdip of a water leg.

The salinity decrease from 25 g/L in the northeast to < 15 g/L in the center, along the boundary to the gas-saturated zone II (Fig. 5.18), coincides with the general flow direction, which is unexpected because salinity generally increases along the flowpath and downdip in other units. Bicarbonate concentrations, increasing towards the south, range between 1 and 3 g/L (Fig. 5.19) and, are similar to concentrations in the overlying aquifers.

Mannville aquifers

Figures 5.20 to 5.27 present, respectively, the distribution of freshwater hydraulic heads, $p(d)$ - and $p(z)$ -plots, and distributions of salinity and bicarbonate in the Mannville aquifers. Hydraulic heads in subzone Ia of the Upper and Lower Mannville aquifers vary from 700 to 550 m, and 600 to 550 m, respectively (Figs. 5.20 & 5.21), with the maximum value being higher than that of hydraulic heads in the overlying Viking aquifer. Hydraulic heads in the Upper Mannville aquifer generally decrease eastward from highs (700 m) in the northwest, suggesting eastward flow along the northern boundary of the study area, with the flow originating from the north of the study area. In the Lower Mannville aquifer, hydraulic gradients in subzone Ia indicate relatively stagnant flow conditions, with the exception of restricted flow towards the underpressured subzone Ib in the east. Subzone Ib in the Mannville aquifers is relatively small and restricted to a narrow band of low hydraulic heads between the gas-saturated zone and the sub-hydrostatically pressured water in subzone Ia. The gas-saturated zones II in the Upper and Lower Mannville aquifers have a similar configuration as that in the Viking aquifer, except for a closed subzone IIb of sub-hydrostatic gas that can be observed in the northeast in the Upper Mannville aquifer (Fig. 5.20). Pressure variations with depth and elevation in the Upper and Lower Mannville aquifers show the same trend as in the Viking aquifer, indicating a relatively moderate change in pressure from zone Ia to Ib (Figs. 5.22 & 5.23).

The salinity data from the Upper Mannville aquifer generally increase northward from 9 to 36 g/L (Fig. 5.24) and are slightly higher in value to the salinity range in the overlying Viking aquifer. Formation water salinity in the Lower Mannville aquifer (Fig. 5.26) ranges between 35 g/L in the north and 90 g/L in the northwest, with a general trend of downdip increase in salinity. The bicarbonate concentration in both Mannville aquifers ranges approximately between 0.5 and 2.5 g/L (Figs. 5.25 & 5.27). In the Lower Mannville aquifer the bicarbonate concentration decreases towards the south, opposed to the trend of increasing salinity, whereas in the Upper Mannville aquifer it increases in that direction.

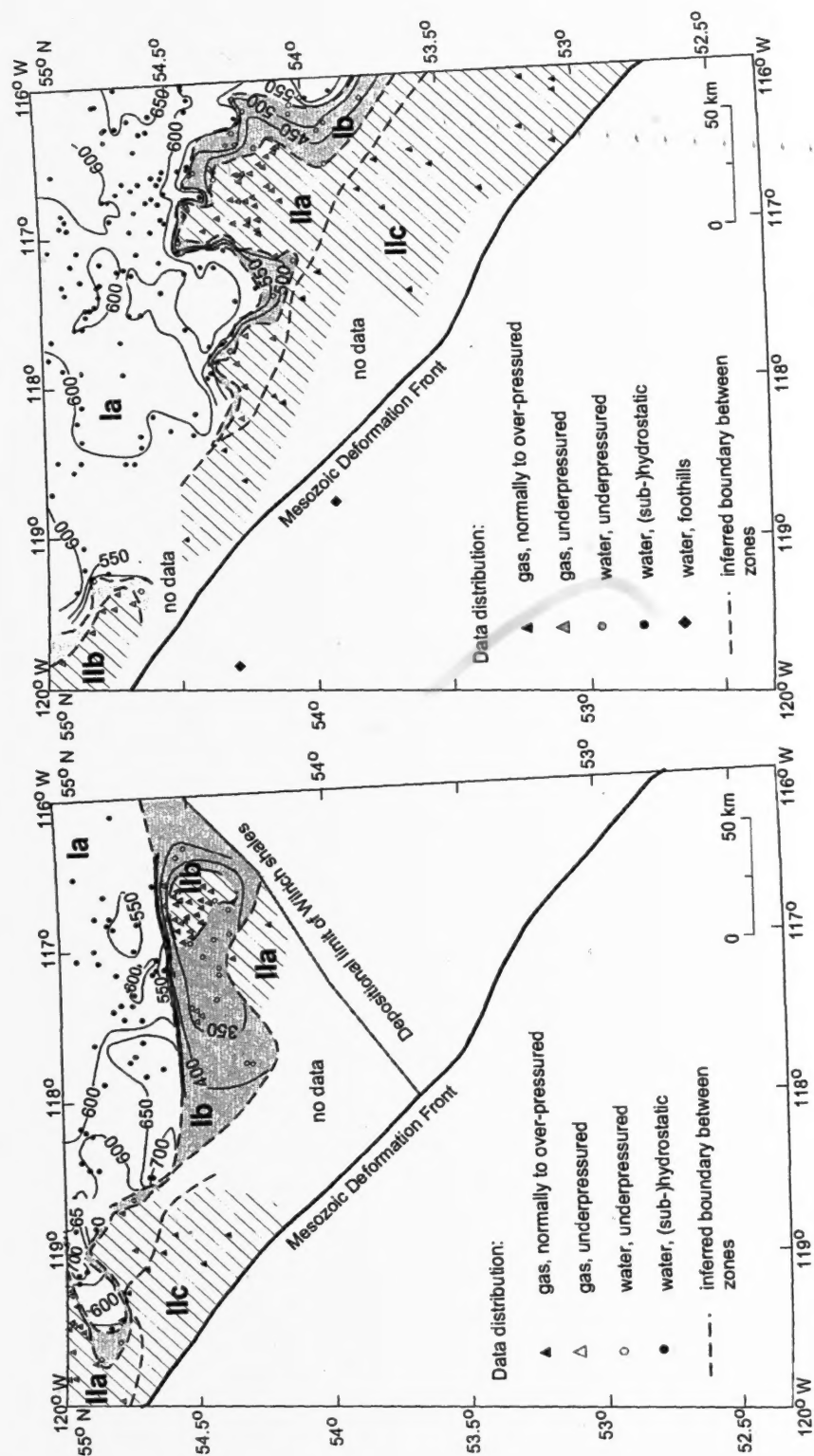
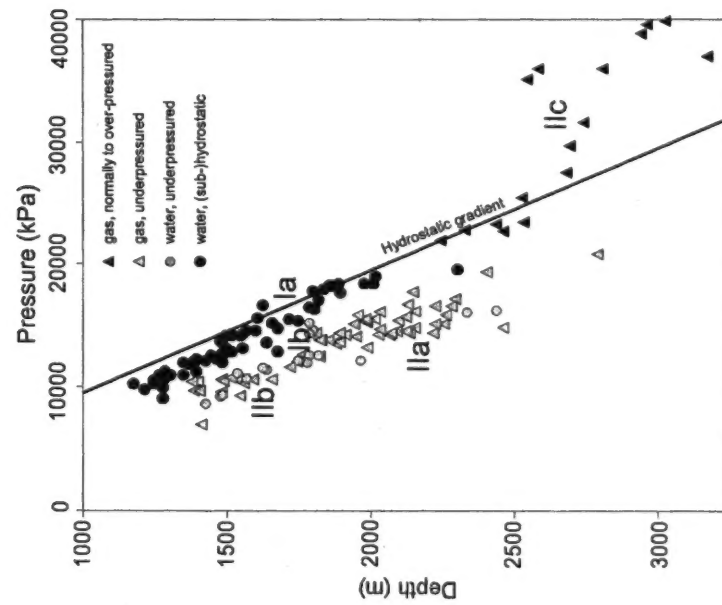


Figure 5.21: Freshwater hydraulic head distribution and aquifer zonation in the Lower Mannville aquifer (50 m contour interval).

Figure 5.20: Freshwater hydraulic head distribution and aquifer zonation in the Upper Mannville aquifer (50 m contour interval).

a.



b.

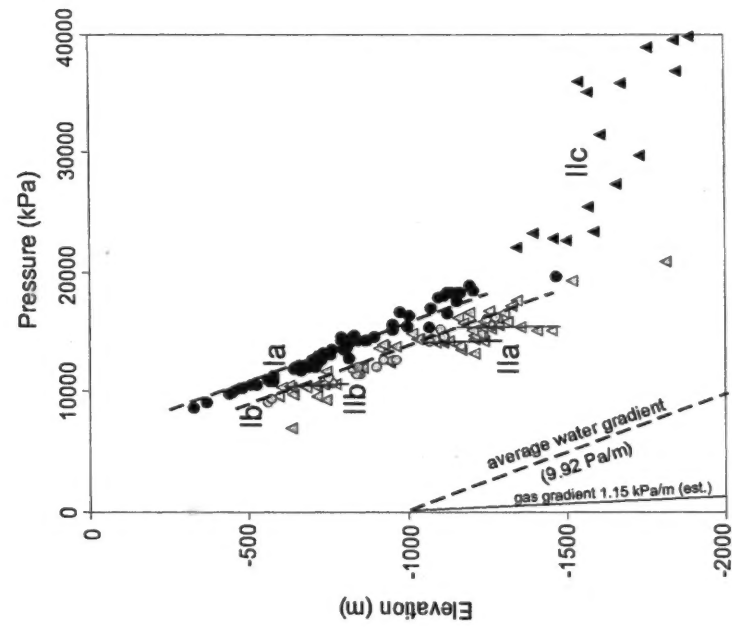


Figure 5.22: Pressure variation with: a) depth and b) elevation in the Upper Mannville aquifer. The data groups denoted by roman numbers correspond to the geographic distributions shown in Figure 5.20.

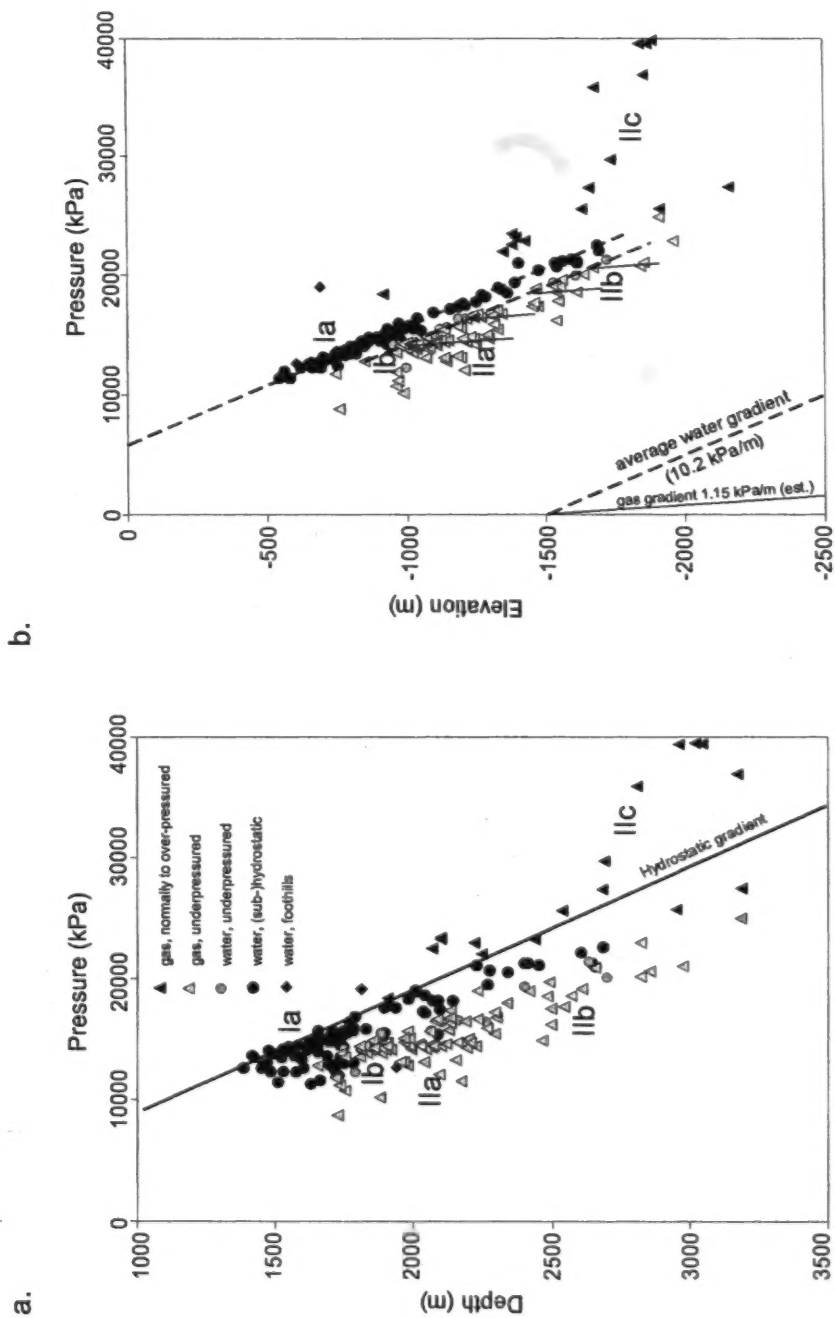


Figure 5.23: Pressure variation with: a) depth and b) elevation in the Lower Mannville aquifer. The data groups denoted by roman numbers correspond to the geographic distributions shown in Figure 5.21.

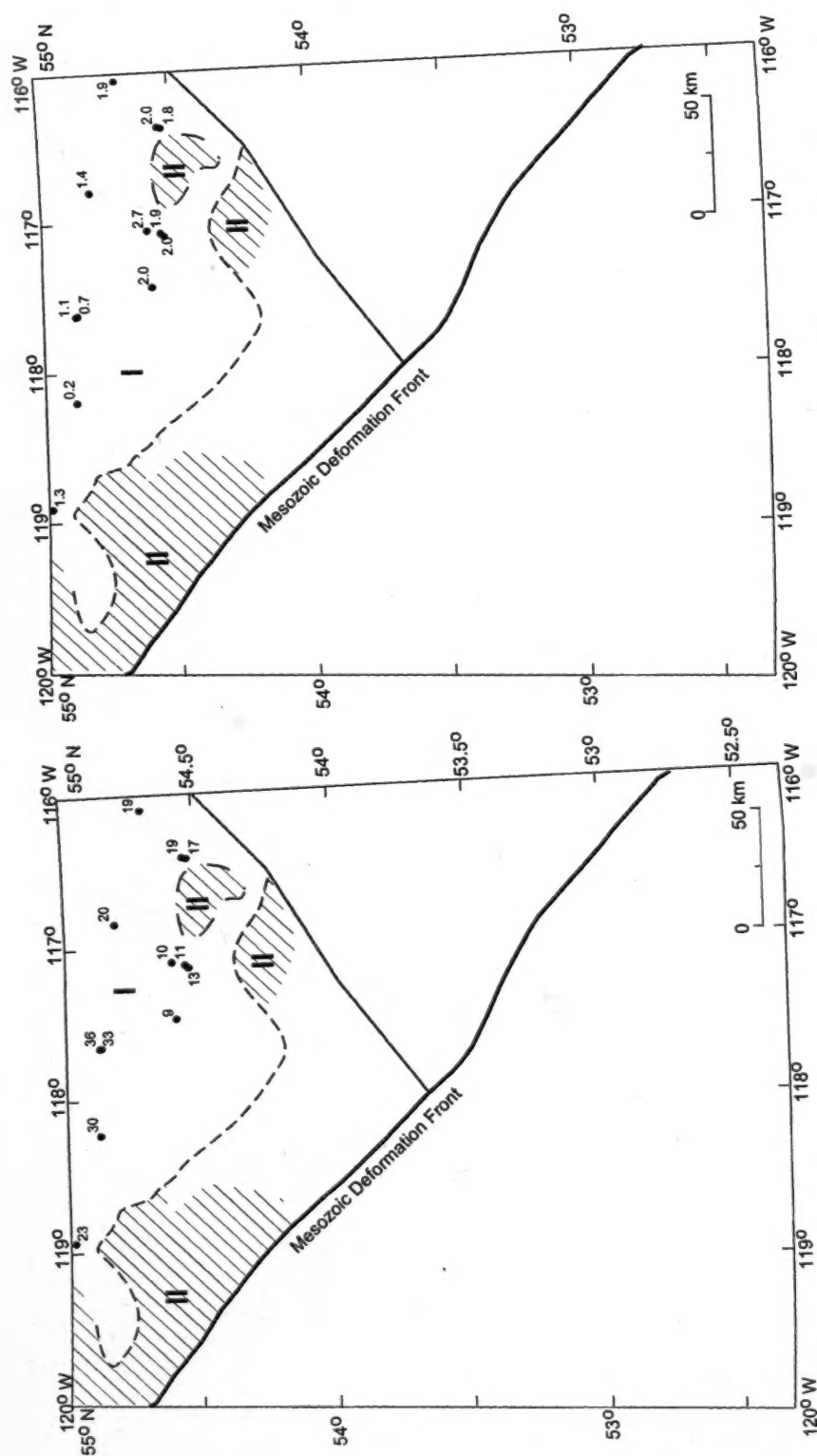


Figure 5.24: Salinity distribution in the Upper Mannville aquifer (point values in g/l). Zones I and II correspond to the zonation in Figure 5.20.

Figure 5.25: Bicarbonate distribution in the Upper Mannville aquifer (point values in g/l). Zones I and II correspond to the zonation in Figure 5.20.

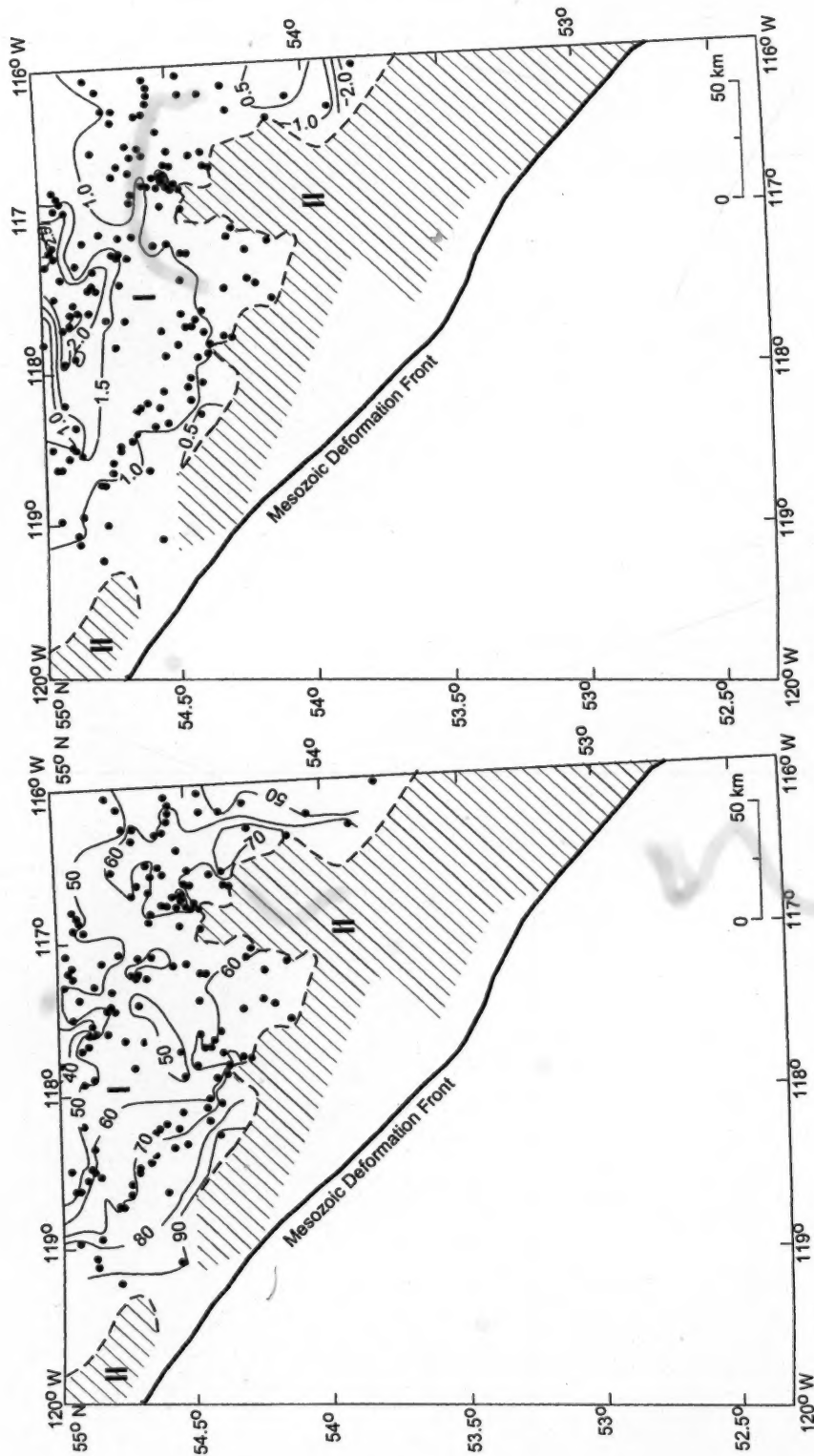


Figure 5.26: Salinity distribution in the Lower Mannville aquifer (10 g/l contour interval). Zones I and II correspond to the zonation in Figure 5.21.

Figure 5.27: Bicarbonate distribution in the Lower Mannville aquifer (0.5 g/l contour interval). Zones I and II correspond to the zonation in Figure 5.21.

Cation-chloride systematics

The variation in the major cations with respect to the chloride concentration are shown in Figure 5.28 and are compared to the composition of average seawater and the seawater-dilution curves experimentally derived by McCaffrey et al. (1986). Sodium concentrations in all aquifer units plot along the seawater evaporation-dilution trend (SET) (Fig. 5.28a). In contrast, formation waters are significantly depleted in magnesium in comparison to the SET (Fig. 5.28b), whereas calcium concentrations plot below and above the SET (Fig. 5.28c).

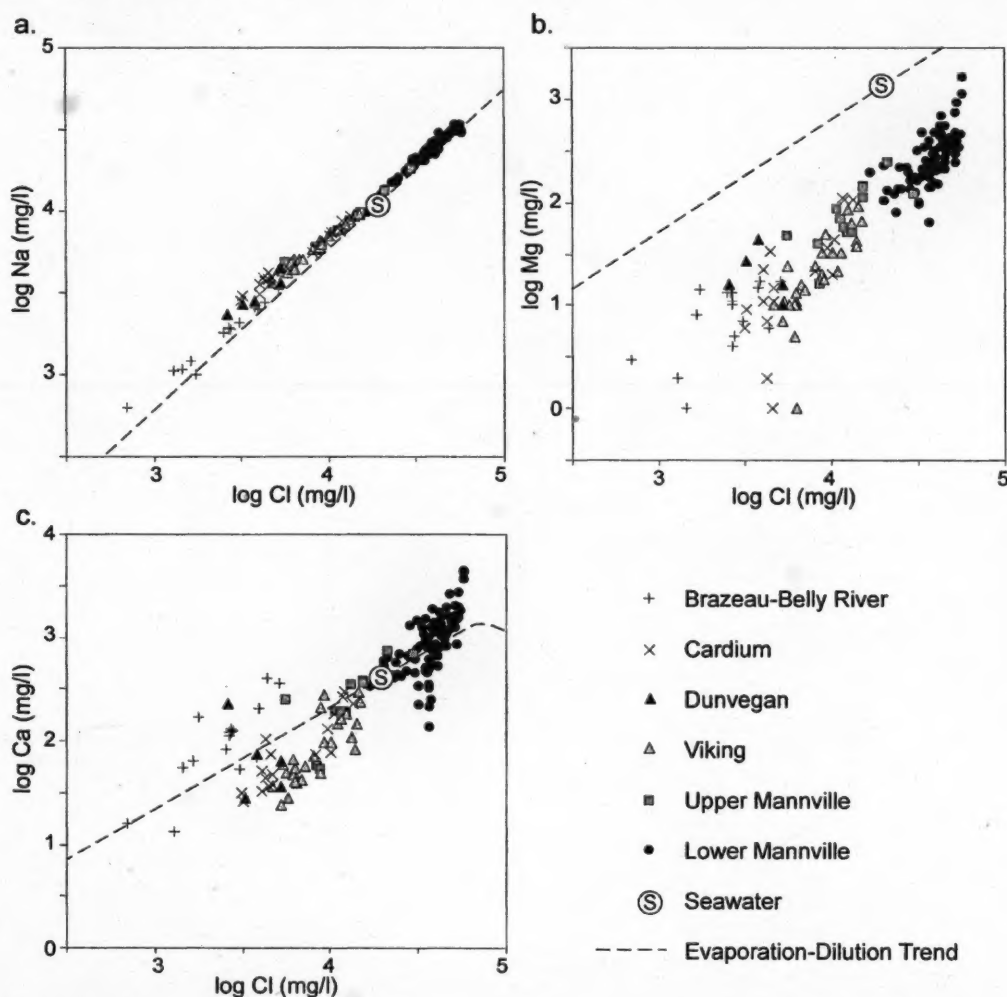


Figure 5.28: Cross plots versus chloride of: a) sodium, b) magnesium, and c) calcium for Cretaceous formation waters in the study area. The various evaporation trends were determined experimentally by McCaffrey et al. (1986).

Summary of hydrogeological analysis

- The Mannville-to Brazeau-Belly River aquifers all have a hydrocarbon-saturated zone (II) downdip of a water-saturated zone (I).
- The hydrostatic to sub-hydrostatically pressured water-saturated subzone (Ia) is separated in most aquifers from the hydrocarbon-saturated zone by an underpressured water subzone (Ib). The only exception is the Cardium aquifer, where subzone Ia lies directly updip of subzone IIb in the northwestern part of the aquifer.
- The areal extent of the underpressured water-saturated subzone Ib successively increases with depth until it reaches its maximum in the Viking aquifer. In the Mannville aquifers it narrows down to a relatively thin band. The average hydraulic head values in subzone Ib also decrease with depth to a minimum of ~200 m in the Dunvegan aquifer, but increase again in the Viking and Mannville aquifers.
- The fluid type and the pressure in the hydrocarbon-saturated zone change (Tab. 5.1), while the area it encompasses increases with depth: Brazeau-Belly River – oil, underpressured; Cardium – oil, overpressured (IIa & b) and gas, normally pressured (IIc); Dunvegan – gas, normally pressured; Viking and Mannville – gas underpressured (IIa & b) and gas, normally to overpressured (IIc).
- The main hydrochemical trend is the increase in salinity with depth. A salinity of formation waters < 15 g/L is observed in the post-Colorado aquifers and in subzone Ia in the Cardium and Dunvegan aquifers. An approximate range of 15 – 30 g/L represents formation waters from the Viking aquifer and isolated parts (zone Ib) in the Colorado aquifers, and a 35 – 90 g/L range characterizes Mannville Group water. For comparison, modern-day seawater has a salinity of approximately 35 g/L.
- Generally, post-Jurassic formation waters are depleted in magnesium compared to evaporated or diluted seawater.

5.4 Interpretation of flow patterns and fluid distributions

Several general conclusions can be drawn from the hydrogeological analysis presented above that will be further discussed in this section.

- The similarity between hydraulic head distributions and the ground surface relief decreases with depth, which suggests that the vertical hydraulic communication between various aquifers and the ground surface decreases with depth.
- The increase of formation water salinity with depth, up to three times higher than that of seawater, suggests that the penetration of fresh meteoric water into deeper aquifers is limited.
- Magnesium and calcium concentrations indicate that other or additional processes than seawater evaporation and dilution must have influenced the evolution of formation waters.
- The subdivision of each aquifer into (sub-)zones, as shown in sharp changes in fluid and pressure distributions, suggests the existence of *lateral permeability or transmissivity changes* in each aquifer (see Chapter 2, 2.3), which results in retardation of pressure equilibration between (sub-)zones and/or the escape of hydrocarbons generally located downdip.
- The hydrogeological similarities between certain adjacent aquifers or parts thereof may indicate areas of *cross-formational flow* across weak aquitards. On the other hand, discontinuous changes in fluid pressure or water chemistry between aquifers imply that the intervening aquitards are effective barriers to flow.
- The existence of large hydrocarbon-saturated zones in the aquifers implies that, at least at some point in time, the rate of hydrocarbon generation was high enough to displace the connate water from the pore space. Therefore, it seems that *hydrocarbon generation and migration* have influenced and continue to influence the flow of formation water.
- Severe underpressuring in parts of the aquifers suggests that at least one alternative *flow-driving mechanism*, different from topography-driven flow, must be active in this part of the Alberta Basin. These underpressures can only be maintained in an overall *low-permeability environment* (see Chapter 2).

Aquitard competence and cross-formational flow

The aquitards in the study area are generally formed by shaly formations that separate or subdivide the various aquifers. The main aquitards are: Battle, Bearpaw, Lea Park, the cumulative Colorado shales, Joli Fou, and Wilrich (Fig. 5.2), which will be discussed in the order of their occurrence from the ground surface downwards.

The relatively fresh water in the Brazeau-Belly River aquifer and the similarity between the hydraulic head distribution and the ground surface relief suggest that the intervening Battle and Bearpaw aquitards are leaky. Nevertheless, they introduce sufficient resistance to flow for hydraulic heads to be below the ground surface, thus indicating semi-confined flow conditions in the Brazeau-Belly River aquifer.

On the other hand, the lack of any similarity between the ground surface topography and the hydraulic head distribution in the underlying Colorado and Mannville aquifers and the offset of fluid pressures in the $p(z)$ -plots in Figure 5.29b & c indicate that the Lea Park aquitard and the cumulatively up to 1500 m thick Colorado shales effectively obstruct vertical hydraulic communication between the ground surface and these aquifers. In addition, the relatively high formation water salinity in the Colorado and Mannville aquifers confirms their isolation from meteoric recharge by the intervening Lea Park and Colorado aquitards.

Regarding the hydraulic communication between aquifers embedded in the Colorado shales, the offset of pressures in the $p(z)$ -plot (Fig. 5.29a) show that the intervening aquitards between the water-saturated (sub-)zones in the Cardium and Dunvegan and between the Dunvegan and Viking aquifers are relatively strong in the northwest of the study area. Farther east on the other hand, pressures plot along a similar gradient (Fig. 5.29b) and cross-formational flow appears to be possible. Nevertheless, it should be noted that the intervening aquitards between the respective aquifers in that area are more than 100 m thick, rendering cross-formational flow rather unlikely. In addition, water pressures in the Cardium to Viking aquifers in the $p(z)$ -plot (Fig. 5.29b) are all from the underpressured subzone Ib, and the similarities in pressure distribution could be explained also by a similar sink in each aquifer that extracts water at the same rate in all three aquifers.

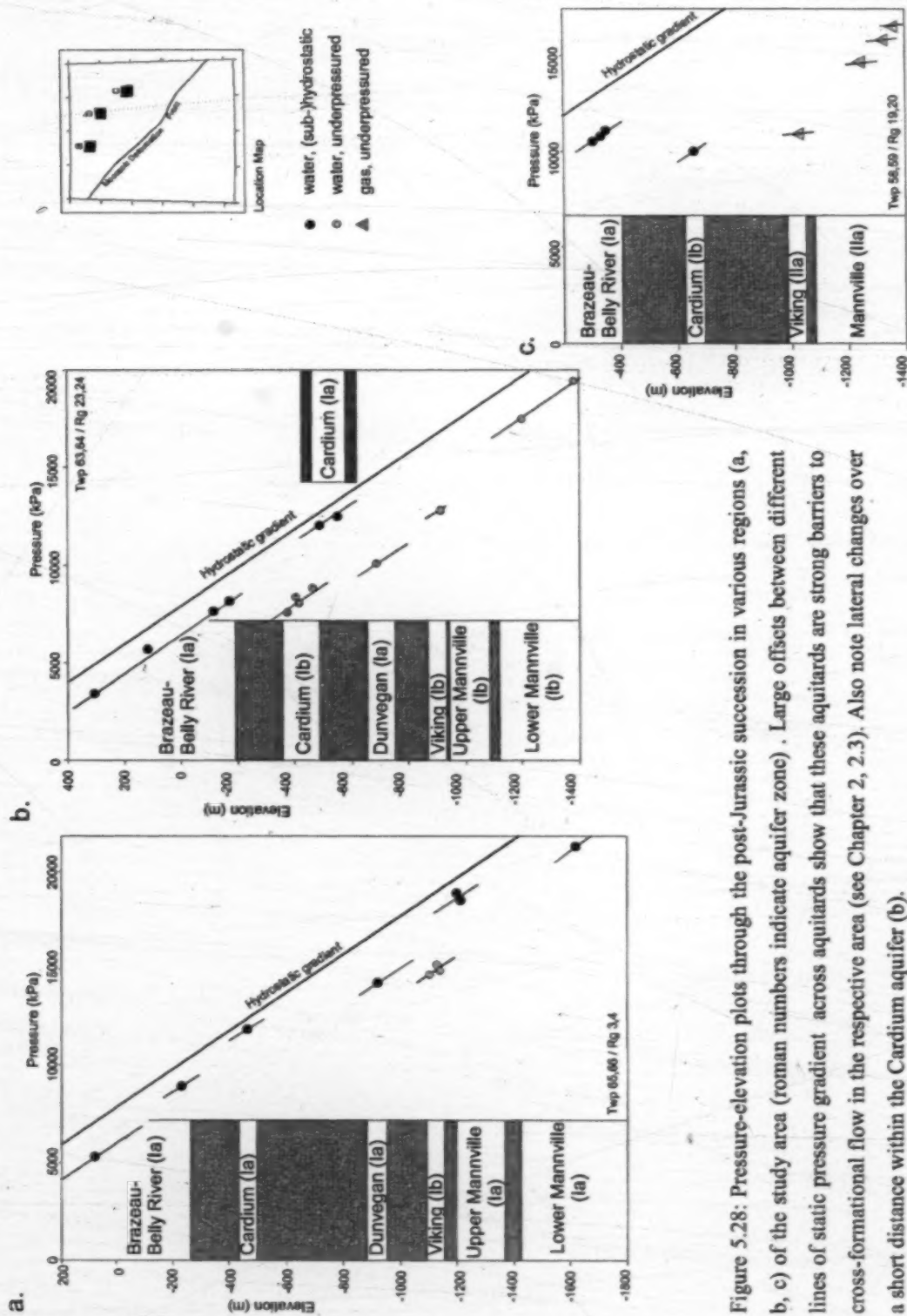


Figure 5.28: Pressure-elevation plots through the post-Jurassic succession in various regions (a, b, c) of the study area (roman numbers indicate aquifer zone). Large offsets between different lines of static pressure gradient across aquitards show that these aquitards are strong barriers to cross-formational flow in the respective area (see Chapter 2, 2.3). Also note lateral changes over a short distance within the Cardium aquifer (b).

The competence of the Joli Fou aquitard has been demonstrated north and northeast of the study area (Hitchon et al., 1990; Bachu and Underschultz, 1993). To the southeast this aquitard appears to be weak or even absent (Rostron and Tóth, 1997), the transition zone most probably running through the study area. Comparing hydraulic heads in the Viking and the Upper Mannville aquifers indicates that the intervening Joli Fou aquitard is strong in the northwest corner of the study area. This is supported by the distinct offset of respective pressure data from these aquifers in the $p(z)$ -plot for that area (Fig. 5.29a). In the northeast on the other hand, hydraulic heads (~550 m) in subzone Ia in the Upper Mannville aquifer are only slightly higher than hydraulic heads (~500 m) in the directly overlying Viking aquifer, so that upward cross-formational flow through the relatively thin Joli Fou aquitard in that area seems likely. Therefore, it appears that the Joli Fou Formation is a strong aquitard only in the northwestern part of the study area, where it is referred to as the Harmon Formation. The aquitard becomes relatively weak towards the east. The gas-saturated region along the deformation front complicates the interpretation of the Joli Fou aquitard competence in that area. A basin-scale study based on oil-source rock correlations suggests that no oils in the Colorado and post-Colorado succession originate from pre-Colorado source rocks (Allan and Creaney, 1991); i.e., the Joli Fou aquitard is strong. Nevertheless, it is entirely possible that gas in the hydrocarbon-saturated zone has migrated from Mannville to Viking reservoirs, but this needs to be established by comparison of gas analyses.

The differences in hydraulic heads and salinity distribution between the Upper and Lower Mannville aquifers and the $p(z)$ -plot (Fig. 5.29a) suggest that the intervening Wilrich shales represent a relatively strong aquitard in the northwestern half of the study area. In the southeastern half the Wilrich shales are absent, which probably allowed gas to escape upward from subzone IIa in the Lower Mannville aquifer, and to form the closed gas accumulation in subzone IIb in the Upper Mannville aquifer (Fig. 5.20).

The high salinities (70 – 90 g/L) in subzone Ia in the northeast of the Lower Mannville aquifer (Fig. 5.26) at the base of the post-Jurassic hydrostratigraphic group probably can be explained by cross-formational flow across a weak Fernie aquitard from the

underlying Triassic aquifer that contains formation water in a comparable salinity and pressure range (see Chapter 6).

Lateral low-permeability barriers

In addition to the competent shale aquitards that impede hydraulic communication with the ground surface and between various aquifers, the distribution of fluids and pressures in the post-Jurassic succession indicates that large-scale lateral permeability barriers exist within the individual aquifers. The barrier in the Brazeau-Belly River aquifer between zones I and II is possibly caused by the lithological change from fluvial, conglomeratic channel deposits to interbedded, non-marine mudstones and sandstones of floodplain origin (Hamblin and Abrahamson, 1996). These sediments were deposited by an anastomosing fluvial system carrying sediments eastward from the Rocky Mountain region, whereby the grain size decreases with distance from the sediment source (Putnam, 1993). Using pressure distributions, Pendergast (1969) inferred lithological barriers to be responsible for the observed hydraulic discontinuities in the Cardium aquifer. Murray et al. (1994) interpreted the compartmentalization of fluids and pressures in the Cardium Formation on the basis of thin sections and capillary pressure analysis as being due to structural rather than lithological changes.

A comparison of the lateral zonation in the various aquifers with the depositional sediment facies (Hayes et al., 1994; Reinson et al., 1994; Bhatthacharya, 1994; Krause et al., 1994) strongly suggests that lithofacies changes and capillary sealing are the main causes for permeability barriers. The gas- and oil-saturated zones are in a region closer to the western sediment source provided by the Columbian and Laramide orogens than the water-saturated zones. The sand-shale ratio generally decreases east – northeastward in all the units. Depositionally coarser material and assumedly more porous material was deposited in the channel fills of the Mannville and Brazeau groups in a coastal plain environment and in the prograding delta of the Dunvegan Formation. In the Cardium and Viking Formations that were deposited in a more marine-influenced environment, the

hydrocarbon-saturated zones correspond mainly with the coastal plain sediments, whereby the normally pressured water is observed in the barrier sands, and the underpressured water zone corresponds to offshore bars embedded in fine-grained sediments. Putnam and Ward (2001) speculated that highly pressured fluid moved updip in the Viking aquifer, leaching certain feldspar and rock fragments at depth, and precipitating solutes, thereby reducing pore space, in shallower environments due to a decrease in pressure and temperature. Also, although the permeability of the aquifers is significantly higher than that of the intervening shale aquitards, a capillary seal is formed when the hydrocarbon phase tries to flow from coarser-grained strata into or through finer-grained sediments (Revil et al., 1998) and the flow of both hydrocarbon and water is blocked.

Topography-driven flow

Hydrogeological cross sections for the post-Colorado aquifer system show semi - confined flow conditions in the Brazeau-Belly River aquifer (Fig. 5.30 & 5.31). The regional potentiometric surface for the Scollard-Paskapoo aquifer is located above the potentiometric surface of the Brazeau-Belly River aquifer, indicating downward flow, while both potentiometric surfaces follow the ground surface in a subdued manner (Fig. 5.30). This suggests that flow in the post-Colorado aquifer system is mainly driven by gravity and has adjusted to the present-day ground surface topography. A certain degree of underpressuring, referred to as "sub-hydrostatic" in zone 1a (Fig. 5.4), can be explained by hydrodynamic effects like a downward component to flow and a partial isolation of the aquifer by the intervening leaky Battle and Bearpaw aquitards. The salinity of formation water is everywhere less than 10 g/L and can be considered as relatively fresh. The high bicarbonate in the northeast is due to direct replenishment by meteoric water, while along the foothills it is due to recharge at topographic highs. The three pressure measurements from the foothills region (Figs. 5.4 & 5.5) suggest flow from that area into the undeformed basin, with the implication that the deep underpressured zone is relatively isolated and by-passed by this flow system (Fig. 5.31). However, lack of data in that area makes it difficult to substantiate this interpretation. The

higher salinity plume in the region at 53.8° N and 116.8° W (Figs. 5.6 & 5.30) at the base of the Brazeau-Belly River aquifer can be explained by a "descending stagnant zone" (Tóth, 1988), that forms a hydraulic trap within the closed high hydraulic head of ~800m (Fig. 5.4). This trapping mechanism is enhanced by the Bearpaw aquitard above the higher salinity plume, which is absent to the northwest. In addition, low bicarbonate concentrations in this area (Fig. 5.7) suggest a very limited influence of meteoric water.

As shown previously, the thick Colorado shales impede vertical fluid flow and pressure transmission, and the current topographic relief does not seem to influence flow in the Colorado and Mannville aquifers. This is substantiated by the hydraulic gradient in subzone Ia of the Cardium aquifer, which is opposed to the slope of the current ground surface and to the flow in the overlying Brazeau-Belly River aquifer, and by the hydrodynamic conditions in the Dunvegan aquifer, which are almost stagnant (Figs. 5.8 & 5.12). In addition, the underpressured subzone Ib in the water-saturated part of each aquifer cannot be explained by a topography-driven flow system. Hence, other flow-driving mechanisms have to be identified that affect fluid pressures in these aquifers.

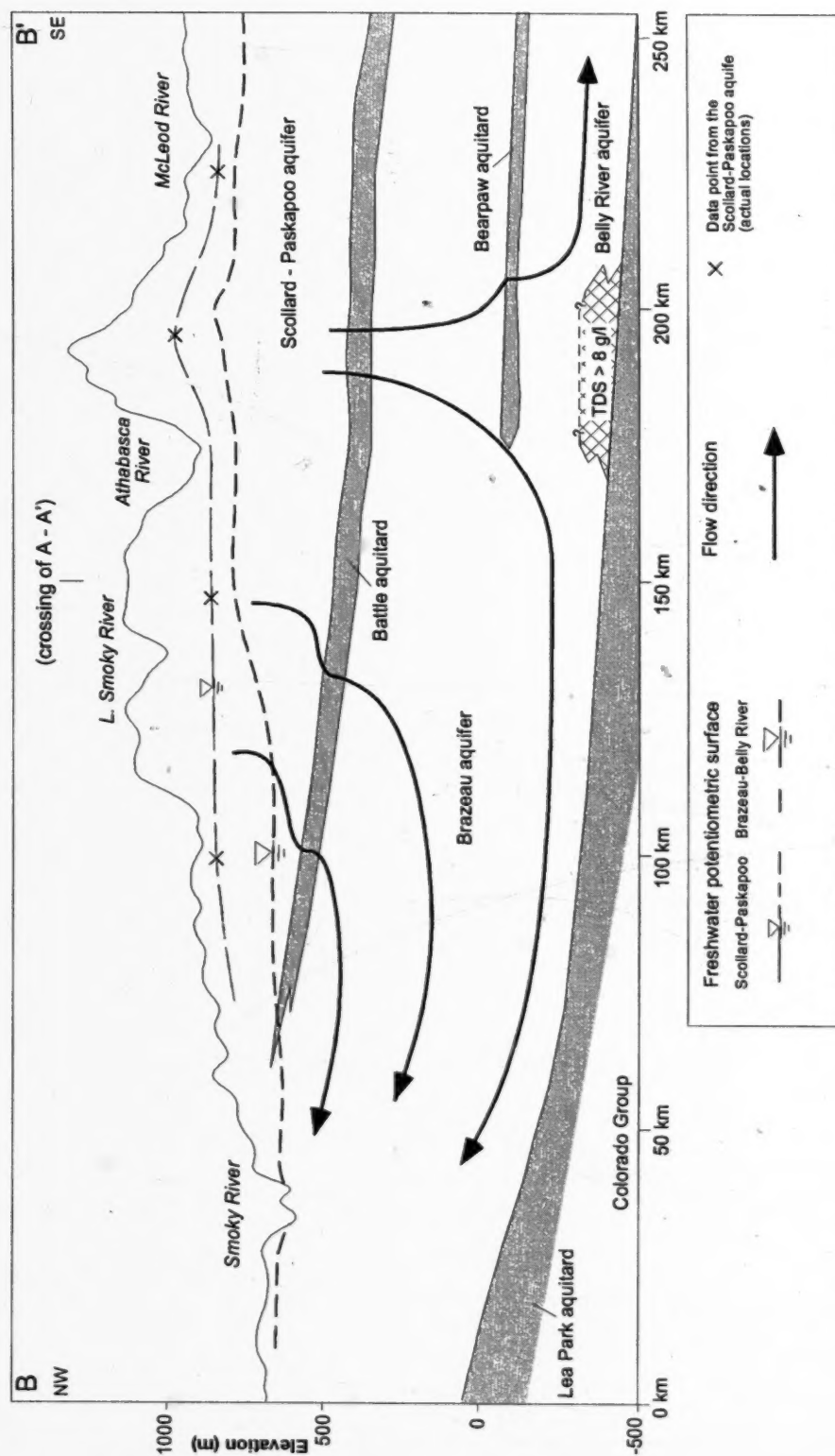


Figure 5.30: Hydrogeological strike cross section of the post-Colorado aquifer system sub-parallel to the deformation front. The potentiometric line of the Scollard-Paskapoo is based on four actual data points ("x"s in cross section), whereas that of the Brazeau-Belly River aquifer is based on the potentiometric surface in Figure 5.4. Also shown is the plume of relatively high salinity in Figure 5.6. See Fig. 5.3 for line of cross section.

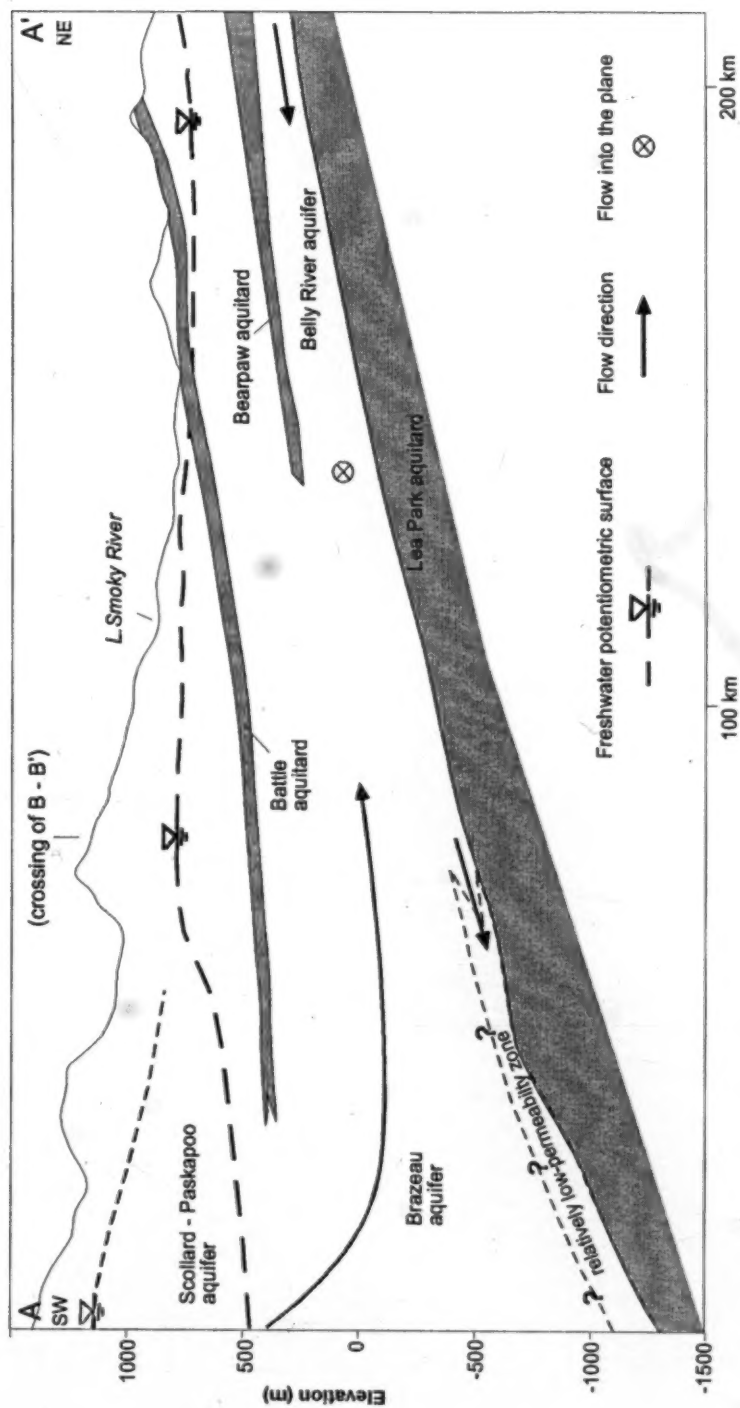


Figure 5.31: Hydrogeological dip cross section of the post-Colorado aquifer system. The potentiometric line and inferred flow directions (black) are based on the potentiometric surface in Figure 5.4. The line and flow arrow in grey represent the extrapolation of hydraulic head values from the foothills region west into the undeformed part of the basin. See Fig. 5.3 for line of cross section.

Hydrocarbon generation and migration

The existence of a hydrocarbon-saturated region in the deep part of the basin implies that formation water was displaced by hydrocarbons thermally generated during burial. These “deep basin” hydrocarbon accumulations are found only along the deformation front of the Alberta Basin (Figure 5.1), which suggests that this region is significantly influenced by the thermal history of the sedimentary succession. Therefore, the thermal history in this part of the basin is reviewed briefly, and the interaction between hydrocarbon generation and migration and fluid flow is investigated in this section.

Foreland-basin petroleum source rocks in the study area, Mannville Group coals and shales, Colorado Group shales, and post-Colorado shales and coals, show various stages of thermal maturity. Maximum vitrinite reflectance R_o max increases with depth and southwestward (Fig. 5.32) from 0.50 % in the coals of the shallow Paskapoo Formation to >2.00 % in Mannville Group coals near the thrust and fold belt (Bustin, 1991; Kalkreuth and McMechan, 1996).

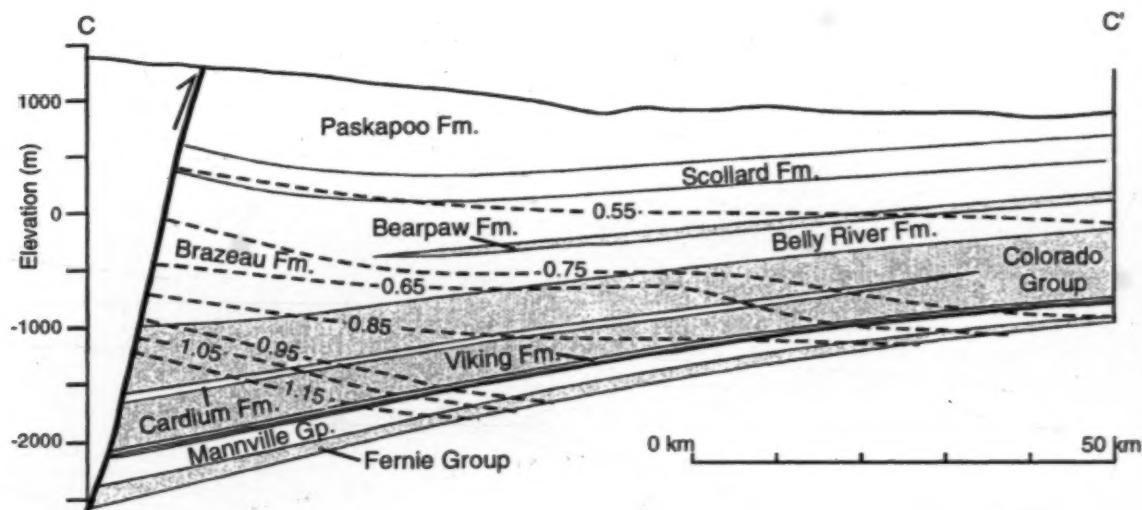


Figure 5.32: Thermal maturity of the foreland-basin strata in the study area (after Bustin, 1991). Isotherms represent vitrinite reflectance R_o max%. See Fig. 5.3 for line of cross section.

The burial history based on vitrinite reflectance (Fig. 5.33) and fluid inclusion data indicates that, at the end of the Laramide orogeny about 53.5 Ma ago, the Lower Cretaceous strata near the thrust and fold belt had reached a maximum burial temperature of $\sim 200^{\circ}\text{C}$ at >7 km depth (Tilley et al., 1989; Kalkreuth and McMechan, 1984).

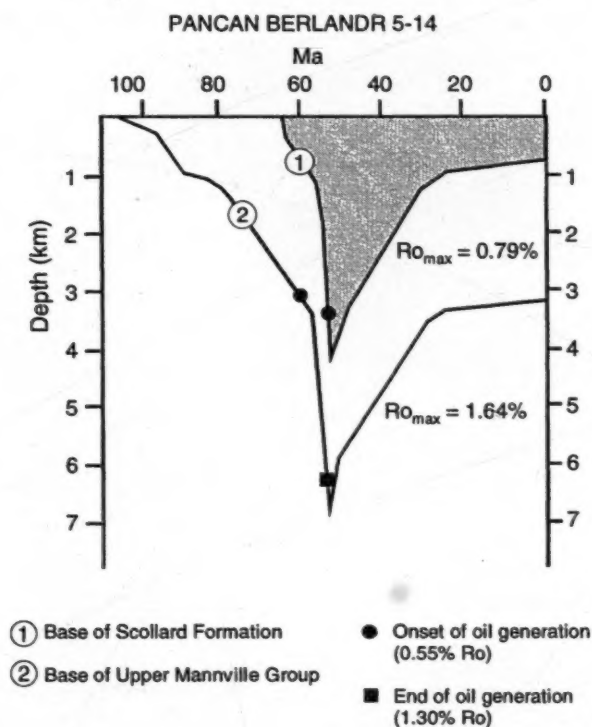


Figure 5.33: Burial history of foreland-basin strata in the PANCAN BERLANDR 5-14 well (from Kalkreuth and McMechan, 1996). See Figure 5.3 for well location.

At the time of maximum burial, the entire Cretaceous succession in the study area was in the oil or gas window. The oil generation window is defined by $R_o_{max} = 0.5 - 1.0 \%$, and the gas generation window by $R_o_{max} = 1.0 - 1.35 \%$, which approximately translates to temperature ranges of 60 to 115°C and 115 to 130°C respectively (Hunt, 1996). The rate of hydrocarbon generation must have been large enough to compensate for the loss of hydrocarbons due to buoyancy-driven migration out of the reservoirs (Masters, 1979,

1984). In addition, a lateral permeability barrier must have existed in each aquifer to obstruct the updip escape of hydrocarbons besides stratigraphic trapping. The aquifers also had to be relatively isolated from the ground surface to prevent aquifer and reservoir flushing by meteoric water, which would have counteracted the displacement of formation waters by hydrocarbons.

Gies (1984) generated a "deep basin" gas accumulation in a laboratory experiment by injecting overpressured gas at the base of a water-saturated, layered, fine-to-coarse sand column (Fig. 5.34). This experiment showed that in-place generated gas could displace water from a relatively highly permeable aquifer or reservoir unit, resulting in a very effective permeability barrier for formation water flow (~ zero relative permeability for water in the gas-saturated zone). More importantly, this experiment demonstrates how originally overpressured hydrocarbon reservoirs can develop into underpressured reservoirs during the uplift of a basin, as theoretically suggested by Law and Dickinson (1985). Stage I represents the period after deposition of the Cretaceous sediments and before the onset of hydrocarbon generation (~ late Paleocene), in which the pore fluid is formation water (Fig. 5.34). Stage II corresponds to the time of deepest burial (Eocene), after thermally generated gas had displaced the water from parts of the aquifer and had formed a gas-saturated zone of maximum extent. Since the Eocene, the Alberta Basin underwent rapid uplift and erosion. This caused a relative downward shift of the oil and gas windows and a concurrent decrease in the rate of hydrocarbon generation, which corresponds to Stage III in Gies' laboratory experiment.

The effectively-lower rate of hydrocarbon generation versus hydrocarbon loss caused a drop in pressure in the hydrocarbon-saturated zone. This allowed formation water to partially re-imbibe the formerly hydrocarbon-saturated zones of the aquifer, causing the downdip retreat of the hydrocarbon-water interface and a shrinking of the areal extent of the hydrocarbon-saturated zone. Remaining hydrocarbon accumulations in the newly water-saturated zone would show "conventional" pressure distributions (Stage IV, Fig. 5.34).

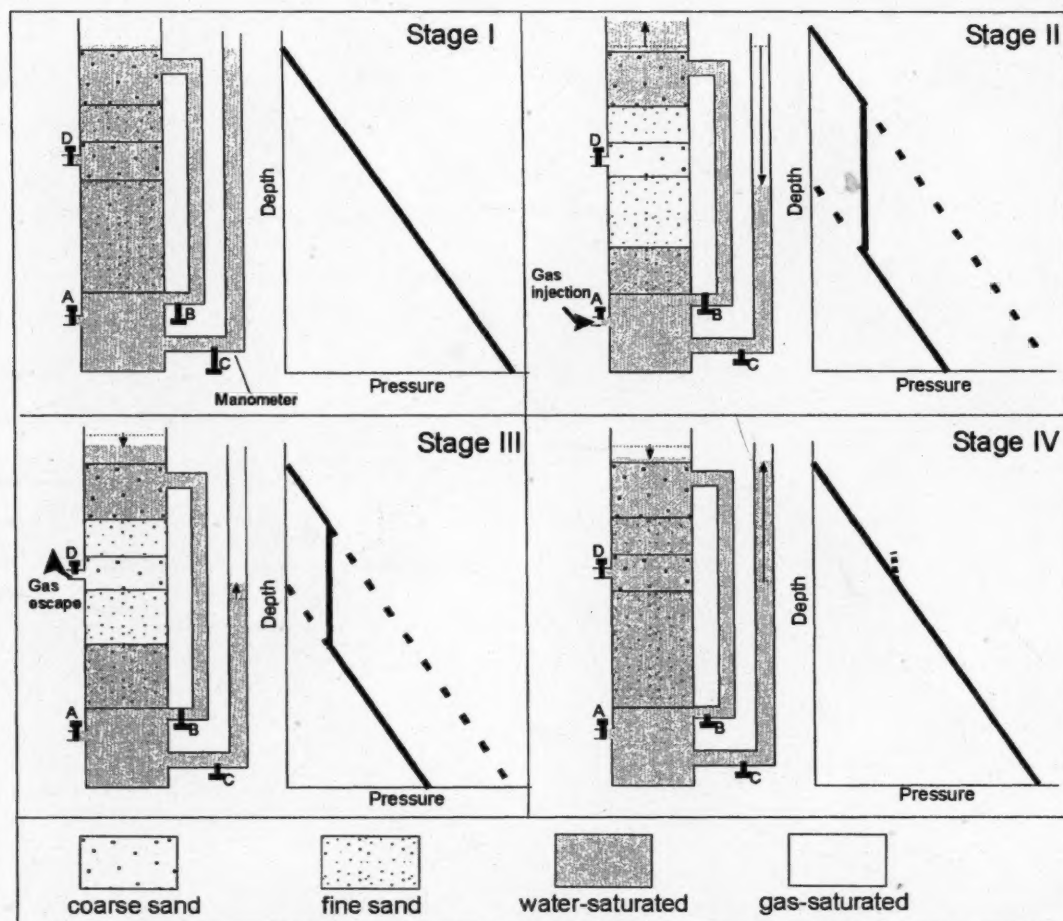


Figure 5.34: Laboratory experiment investigating the hydraulic behavior of "deep basin" gas reservoirs (modified after Gies, 1984): Stage I) initial, water-saturated conditions and pressure distribution; Stage II) pressure conditions after gas injection and water displacement; Stage III) slight change in pressure conditions and fluid saturation after gas escape; Stage IV) return to initial conditions. The dotted line indicates theoretical gas pressure gradient in a (conventional) reservoir unit.

Nevertheless, the advancement of the water front is retarded by the lateral low-permeability barriers, especially in the Cardium and Dunvegan aquifers, which add to the relative permeability barrier. In addition, the amount of water needed to fill the vacated pore space is limited in the Mannville and Colorado aquifers, because they are largely cut off from meteoric recharge that could replenish them. This is probably the main mechanism that created the underpressures in subzone Ib in the Upper and Lower

Mannville aquifers in the study area. The effect of underpressuring is enhanced or may be dominated by the erosional and post-glaciation rebound of the surrounding shales (see next section).

Presently, only the deep strata along the thrust and fold belt generate hydrocarbons. The present-day subsurface temperature distribution was calculated based on average geothermal gradients in the area and rock thermal conductivity (Bachu, 1993). Temperatures in the 60° – 110°C range indicate that the Cardium-to-Belly River source rocks are in the oil window, while the gas-prone Mannville Group coals (kerogen type III) that are the major source rocks for the “deep basin” gas (Welte et al., 1984), are in the gas window (Fig. 5.35). The above-hydrostatic pressures in the various subzones IIa indicate active hydrocarbon generation in a low-permeability environment (Hedberg, 1974; Spencer, 1987; Osborne and Swarbrick, 1997). The representative isotherms for the oil and gas window generally mimic the observed patterns of fluid distribution in the post-Jurassic succession (Figs. 5.35 & 5.36). In the “isolated” Cardium and Dunvegan aquifers that are embedded in the Colorado shales, the northeastern limit of zone II generally tracks the upper limit of the oil window (Fig. 5.36b & c). Apparently the rate of hydrocarbon generation is high enough to maintain those parts of the aquifers saturated with hydrocarbons that are located within the oil window. On the other hand, the Brazeau-Belly River and Lower Mannville aquifers are not embedded in shales, and large parts of these aquifers, although located in the oil window, are not saturated with hydrocarbons (Fig. 5.36a & d). This suggests that the rate of hydrocarbon generation versus hydrocarbon leakage in these aquifers is not or has not been sufficiently high to maintain or generate a deep basin hydrocarbon accumulation over the entire extent of the part of the aquifer that lies within the oil or gas window. In addition, hydrocarbons have escaped, driven by buoyancy, and have been replaced by formation water.

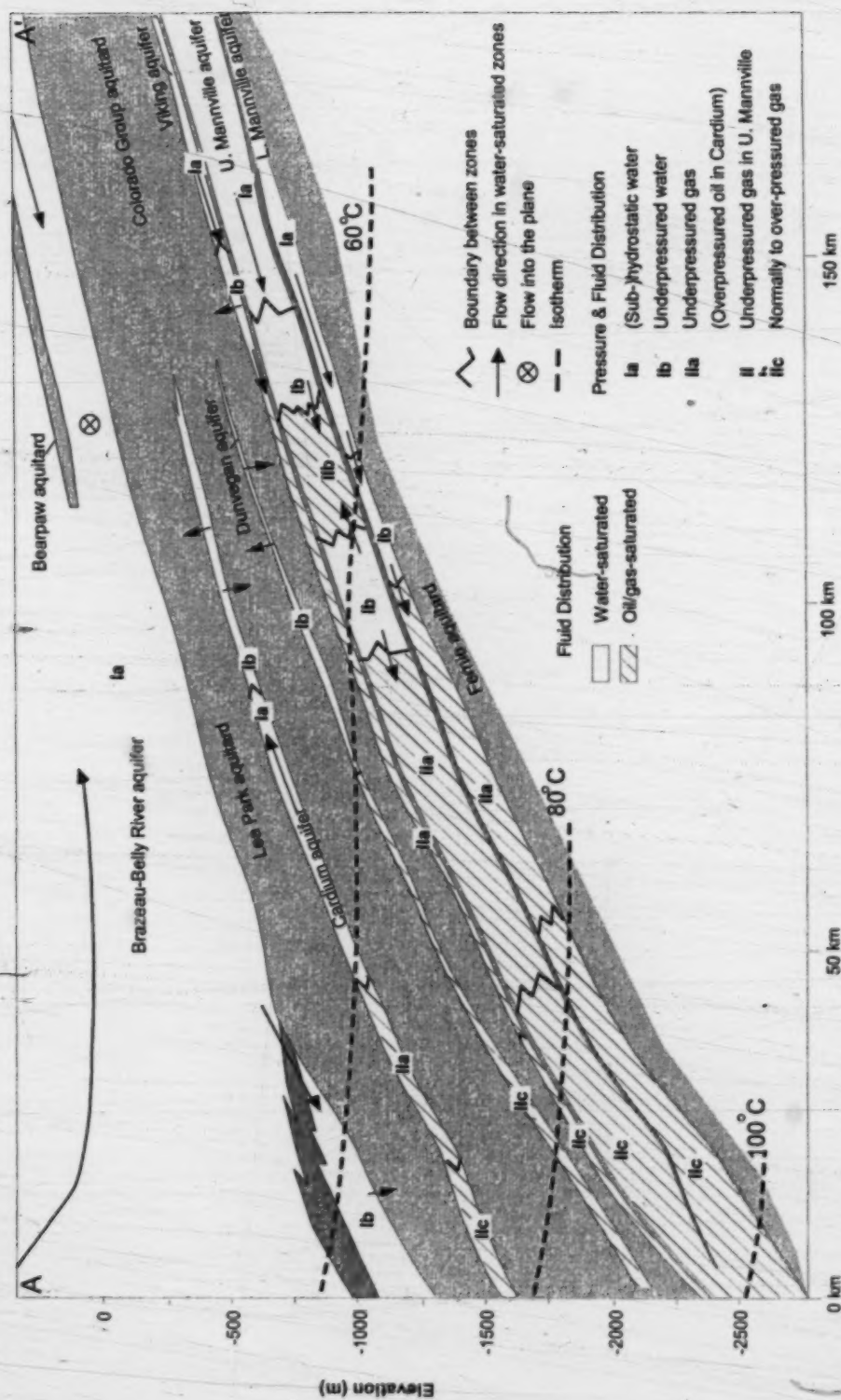


Figure 5.35: Hydrogeological dip cross section (A-A') of the post-Jurassic aquifers showing the inferred flow pattern and fluid, pressure and temperature distributions. (See Fig. 5.3 for line of cross section.)

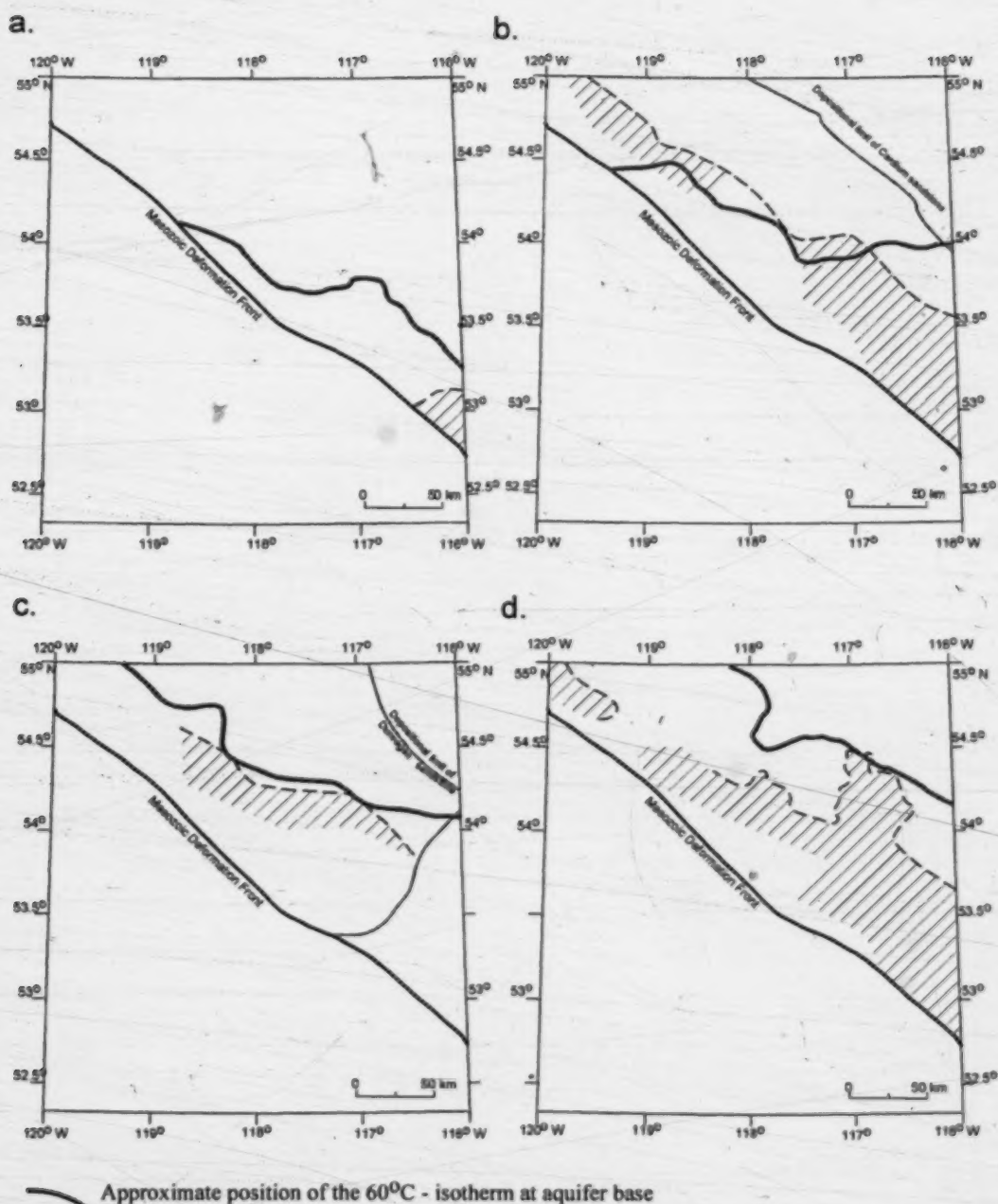


Figure 5.36: Current location of the oil window as inferred from the 60°C isotherm, relative to the aquifer zonation in: a) Brazeau-Belly River, b) Cardium, c) Dunvegan, and d) Lower Mannville, respectively. The hatched area represents the current hydrocarbon-saturated zone. Temperatures are > 60°C west of the isotherm.

Erosional and post-glaciation rebound

The main mechanism currently thought to be responsible for underpressures in the post-Jurassic succession is the "absorbing sponge" effect of thick, low-permeability Colorado shales rebounding after removal of overburden by erosion since the peak of the Laramide orogeny and post-glaciation rebound. This effect has been demonstrated theoretically (Neuzil and Pollock, 1983; Neuzil, 1986), and inferred (Bachu and Underschultz, 1995, Parks and Tóth, 1995), and numerically simulated for the Alberta Basin (Corbet and Bethke, 1992; Bekele et al., 2000). The westward increase in underpressuring can be explained by a greater amount of sediment removal close to the foothills than in the east (Bustin, 1991; Kalkreuth and McMechan, 1996; see also Fig. 4.8a in Chapter 4), which implies an originally higher degree of shale compaction and which necessitates a longer transient time to equilibrate. The permeability of the intervening shales has to be sufficiently low to preserve underpressures in the Cretaceous aquifers. Local- and regional-scale permeability in the order of $10^{-20} - 10^{-21} \text{ m}^2$ (Neuzil, 1994; Bekele et al., 2000) and an erosional hydraulic diffusivity, defined as hydraulic conductivity divided by the specific storage (Freeze and Cherry, 1979, p. 61), of $10^{-9} - 10^{-8} \text{ m}^2/\text{s}$ (Neuzil and Pollock, 1983; Parks and Tóth, 1995) correspond to a characteristic time for pressure dissipation in the order of 1 – 5 Ma. This is comparable with the period since the start of Tertiary to Holocene erosion and glaciation events. The effect of recent glaciation cycles during which the Laurentide ice sheet in the area reached 1-2 km in thickness (Matthews, 1974) compounded erosional rebound since the Tertiary (Bachu, 1995a). According to recent numerical modeling results, glacial unloading could be even the dominating mechanism for creating the observed underpressures in the Alberta Basin (Bekele, 1999).

In the study area, the Colorado shales and the lateral permeability changes in each aquifer provide for the low-permeability environment that is necessary to impede fluid and pressure transmission, hence maintain non-hydrostatic pressures in the subsurface. The change in the areal extent of subzone Ib in various aquifers in the succession strongly supports the idea that erosional rebound is an important mechanism for creating underpressures in the post-Jurassic succession in the study area.

The rebounding Colorado shales represent a pressure sink that "sucks in" fluids from the imbedded (Cardium, Dunvegan, Viking) and over- and underlying Brazeau-Belly River and Mannville aquifers, respectively. The underpressured water-saturated subzone Ib in the Brazeau-Belly River aquifer is relatively small compared to the underlying aquifers, because that aquifer is not imbedded in shales and fluids only are drawn into the Lea Park shales at the base of the aquifer. The existence of this subzone and its persistence in time indicate that there must exist a vertical and lateral barrier to flow that prevents the dissipation of the underpressures from that subzone and equilibration with the topography-driven system in the Brazeau-Belly River aquifer. In the Cardium and Dunvegan aquifers, which are imbedded in the Colorado shales, subzones Ib are more extensive, but these aquifers still are partially, sub-laterally connected hydraulically to the ground surface in areas of aquifer outcrop, and underpressures can easily equilibrate in those areas. An effective combination of isolation from the ground surface and embedding in the rebounding Colorado shales is observed in the Viking aquifer, causing very low hydraulic heads and a maximum areal extent of subzone Ib. There are no significantly thick shale units within the Mannville aquifer system that could draw-in fluids, so that fluids from the Upper and Lower Mannville aquifers can only be "sucked in" by the overlying Colorado shales. This might explain the narrow subzone Ib in both aquifers. An additional mechanism that could be responsible for the underpressures in the Upper and Lower Mannville aquifers is the effect of hydrocarbon generation and migration in the deep parts of the basin as shown in the previous section. The hydrogeological dip cross section A-A' (Fig. 5.35) illustrates these considerations on fluid pressure distributions in the post-Jurassic succession.

Chemical evolution of formation waters

Sediments in the post-Jurassic succession were deposited in a marine to marginal-marine environment and, therefore, the respective formation waters probably started out as seawater that was successively altered by water-rock interaction and mixing with

meteoric water after or during sediment deposition. The sodium and chloride concentrations compared to seawater values suggest that formation waters in the Brazeau-Belly River to Viking aquifers, and the Lower Mannville aquifer, represent diluted and concentrated seawater, respectively, while concentrations from the Upper Mannville aquifer fall in-between the two (Fig. 5.28a). Magnesium and calcium concentrations do not follow the seawater dilution-evaporation trend (Fig. 5.28b & c), which indicates that additional mechanisms must have affected the chemistry of formation waters. The consistently low magnesium concentrations can be explained by the precipitation of dolomite cements shortly after sediment deposition and cation exchange. The relatively high calcium concentrations in the Brazeau-Belly River aquifer are probably due to the shallow depth to the ground surface and mixing with high-calcium waters from shallow aquifers. The low calcium concentrations with respect to the seawater evaporation-dilution curve in the underlying aquifers could be caused by calcite precipitation and cation exchange in montmorillonite shales (Freeze and Cherry, 1979), whereas the excess in calcium, especially in the Lower Mannville aquifer is probably due to the dissolution of calcite and/or sulphate.

Plotting the Na/Cl-ratio versus salinity clearly shows a different grouping of formation waters in the various post-Jurassic aquifers (Fig. 5.37). Waters from aquifers connected to the ground surface (Brazeau-Belly River, Cardium Ia, and Dunvegan Ia) have a relatively wide range in the Na/Cl-ratios and salinities (TDS < 12 g/L) significantly lower than seawater, indicating extensive flushing with meteoric water. The salinity of waters from the isolated parts of the Cardium (zone Ib), the Viking, and the Upper Mannville is slightly higher, and the data follow a tentative mixing trend between seawater and meteoric water (Fig. 5.37). Only data from the Lower Mannville aquifer have a narrow range in Na/Cl-ratios (0.85 - 1.0) and a wide range in salinities, suggesting a relative high degree of halite solution and/or mixing with more-saline brine from the underlying Jurassic-Mississippian aquifers.

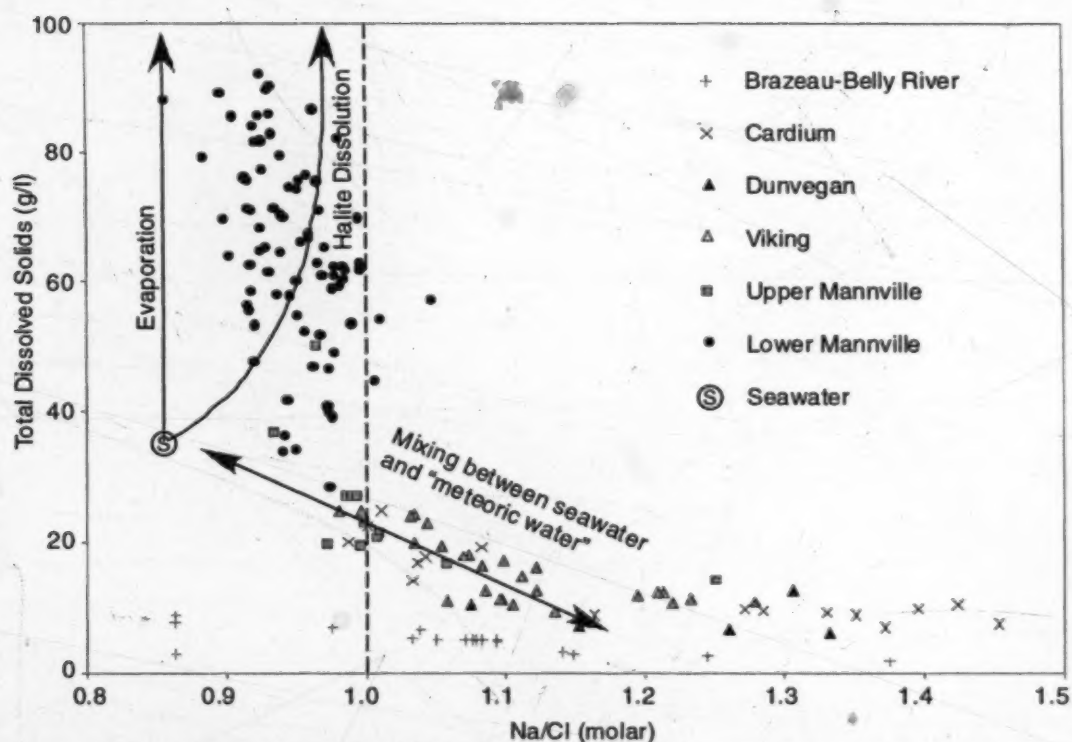


Figure 5.37: Na/Cl-ratio versus salinity plot of Tertiary-Cretaceous formation waters showing tentative trends of evaporation, halite dissolution and mixing.

Aquifer recharge and flow paths

So far, it has been shown that flow in the post-Colorado aquifers is driven by topography, and that the respective formation waters are of meteoric origin, as suggested by the low salinity and bicarbonate distribution. On the other hand, erosional and post-glaciation rebound, and the interaction between hydrocarbon- and water-saturated zones, are interpreted to be the main flow driving mechanisms in the Colorado and Mannville aquifers. According to this interpretation, the rebounding Colorado shales and the retreat of the hydrocarbon-saturated zone represent the fluid sinks in these aquifers, whereas the fluid origin and the flow paths still have to be established. This task is complicated by the lateral permeability barriers that restrict fluid flow within each individual aquifer, and that cause their compartmentalization into zones and subzones.

The generally low salinity and the increase in salinity with distance from aquifer outcrop indicate that subzones Ia in the Cardium and Dunvegan aquifers appear to be the only ones that are laterally connected to the ground surface in areas of formation outcrops outside the study area. Furthermore, the salinity distribution suggests that a plume of meteoric water ($\text{TDS} < 15 \text{ g/L}$ in subzone Ia) has partially penetrated these aquifers that were originally deposited in a marginal-marine environment. Remainders of the connate brackish to marine pore water are represented by salinities $> 20 \text{ g/L}$ in subzone Ib in the Cardium aquifer. Obviously, this freshwater recharge did not happen as a result of the present-day topographic relief, because the respective aquifers crop out at low elevations, nor can it be explained by cross-formational flow of meteoric water downward through the competent intervening Lea Park aquitard. One possibility would be the lateral pressure-induced intrusion of Pleistocene melt water from the respective aquifer outcrops, similar to an interpretation for the Williston Basin (Grasby and Betcher, 2000). The continental ice sheet, 1- 2 km thick (Matthews, 1974), would have provided the hydraulic drive for this intrusion. Another case of deep recharge of glacial melt water to depths between 700 to 1600 m was demonstrated on the Canadian Shield at the northern edge of the Alberta Basin, by analyzing oxygen isotopes and salinity distributions, and by using numerical flow modeling (Clark et al., 2000). The downward penetration of melt water in the study area could have been facilitated by the existence of an ice-free corridor (see Chapter 4, Fig. 4.7 b) sub-parallel to the deformation front (Rutter, 1984). This area would have been more susceptible to the infiltration of precipitation and surface run-off than the area underneath the Laurentide ice-sheet. Although the latter hypothesis provides a possible explanation, the origin of the relatively fresh water plume in the Cardium and Dunvegan aquifers needs further investigation using isotope data of oxygen and hydrogen.

The cumulative thickness of the Colorado shales (~ 1500 m) and the flow pattern in the Cardium and Dunvegan aquifer suggest that strictly vertical cross-formational flow of recharging meteoric waters into the Viking and lower aquifers is improbable. Direct lateral meteoric recharge of the Viking and Mannville aquifers from the undeformed part

of the basin is rather unlikely, because these aquifers crop out hundreds of kilometres to the northeast of the study area. Generally, recharge of the Colorado and Mannville aquifer systems by meteoric water from the thrust and fold belt is not possible, because the hydrocarbon-saturated zone along the deformation front in each aquifer represents a continuous lateral pressure and relative-permeability barrier to formation water flow. Although the Mannville to Viking sediments were deposited mainly in a fluvio-deltaic environment, the originally relatively fresh formation waters should have dissolved solutes from the surrounding rock framework with time, and should have mixed with marine waters during and after deposition of the Colorado shales. The relative low salinities < 15 g/L in areas of the Viking and Upper Mannville aquifers can therefore only be explained by either partial flushing of these aquifers by glacial melt water during the Quaternary, as hypothesized for the Dunvegan and Cardium aquifers, or by the isolation of parts of the aquifers, shortly after deposition of the Viking and Mannville sediments before hydrocarbons displaced the formation water. A satisfactory interpretation on the basis of the current flow patterns and salinity distribution is not possible and additional work on isotopes and numerical flow modeling is needed in the future to validate any of these possibilities.

The salinity of formation water (35 – 90 g/L) in the Lower Mannville is significantly higher than that in the overlying aquifers and also higher than seawater, which suggests that the Lower Mannville aquifer in the study area has not been flushed by meteoric water at any time in the basin history. To the contrary, the initially low-salinity water that originated during the time of fluvial and deltaic sedimentation was further concentrated by water-rock interaction and mixing with more saline water. This interpretation makes it also unlikely that formation water in the Upper Mannville aquifer was diluted by meteoric recharge from the emerging front of the Columbian orogen shortly after deposition of the sediments, because such a flow system would have also affected the Lower Mannville aquifer. Therefore, having considered all other possibilities, the relatively low salinity in the Upper Mannville aquifer is most likely the result of a flow system and meteoric recharge originating in the northern Peace River Arch region. In contrast, the Lower Mannville formation water was either further concentrated by cross-

formational flow of high-salinity Triassic water through a weak Fernie aquitard in the northwest of the study area, or is part of a long-range flow system from the south-southeast, originating in Montana (Bachu and Underschultz, 1995; Bachu, 1995a; Anfort et al., 2001).

5.5 Conclusions

Fluid flow in the Tertiary-Cretaceous succession in west-central Alberta is closely related to the basin history. Burial of the basin strata and subsequent hydrocarbon generation during the Laramide orogeny created dominantly hydrocarbon-saturated zones in the deeper parts of the Mannville to Brazeau-Belly River aquifers, the hydrocarbons being located downdip of the water-saturated zones. The extent of these "deep basin" hydrocarbon accumulations, as well as the fluid and the pressure distributions, vary between the various aquifers depending mainly on the subsurface temperature, on the kerogen type and on the degree of water penetration. The water-saturated zone directly updip of the hydrocarbon-saturated zones is generally underpressured, suggesting that the rate of hydrocarbon leakage from the reservoir rocks is presently higher than the rate of hydrocarbon generation, and that formation water can re-imbibe these zones. Therefore, the hydrocarbon-water interface may be characterized as a transient relative permeability barrier that moves downdip towards the deformation front with the uplift of the basin. Overpressures are maintained in the deep parts of those hydrocarbon-saturated zones in which the rate of active thermogenic hydrocarbon generation is sufficiently high.

Only in the post-Colorado aquifers has the flow adjusted to the present-day ground surface topography and pressures are sub-hydrostatic as a result of intervening local- and regional-scale shaly aquitards. The Mannville and Colorado aquifers are mainly cut off from meteoric recharge by the Colorado shales aquitard, except for a tongue of freshwater in subzone 1b of the Cardium and Dunvegan aquifers that are connected to outcrop outside of the study area. The degree of penetration of meteoric water into the Viking and Mannville aquifers needs further investigation. Formation water flow in the

Mannville and Colorado aquifers is mostly towards the underpressured hydrocarbon-saturated regions and towards the sinks created by erosional and post-glacial rebound of the intervening shales. The discontinuous changes in fluid distributions (gas, oil water) and pressures (underpressured, sub-hydrostatically pressured, sub-hydrostatic, overpressured) between aquifer zones indicate that absolute and relative lateral permeability barriers impede pressure transmission, hydrocarbon migration and water flow. The hydrocarbon-saturated region represents a relative permeability and pressure barrier to potential meteoric recharge from the thrust and fold belt.

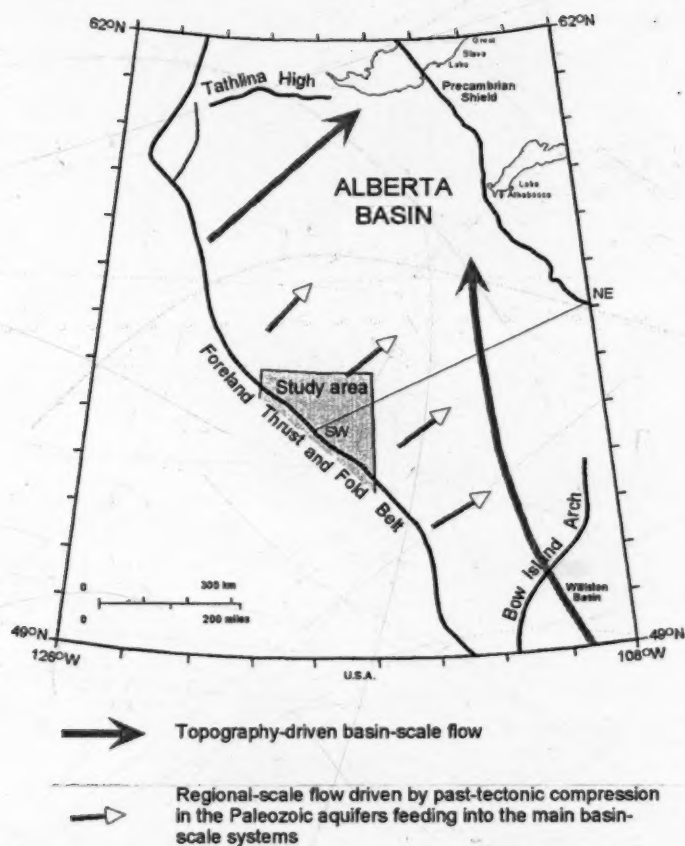
In summary, the present-day hydrodynamic regime represents only the latest stage in the fluid flow evolution and is the result of various factors during the basin history: a) hydrocarbon generation and migration leading to "deep basin" hydrocarbon accumulations during burial of the Cretaceous sediments, b) erosion to the present-day ground surface causing uplift of the sedimentary succession with subsequent decrease of hydrocarbon generation and rebound of the shales, c) a low-permeability environment impeding pressure transmission and fluid flow. Hence, a steady-state topography-driven regional flow system does not exist in this part of the basin.

CHAPTER 6: FLOW OF FORMATION WATER IN THE JURASSIC- MISSISSIPPIAN SUCCESSION

6.1 Introduction

The Jurassic-Mississippian succession represents a transition from dominantly carbonate to siliciclastic sedimentation in the evolution of the WCSB (see Chapter 4). Based on its salinity distribution and flow characteristics, the Mississippian-Jurassic aquifer system was considered as being the upper part of a pre-Cretaceous mega-hydrostratigraphic group (Bachu, 1995a; 1999). Two basin-scale flow systems driven by basin topography and partially flushed by meteoric water are present in this group, hence in this aquifer system: a south-northward one in the south, and a southwest-northeastward one in the north, with a transition zone between the two in the 53°-55°N area (Fig. 6.1a). Based on comprehensive hydrochemical data (e.g., trace and major ion chemistry, and Sr-, O-, H-isotopes), Connolly et al. (1990a,b) divided formation waters in west-central Alberta into three groups. Waters from dominantly Devonian carbonate aquifers (Group 1), which represent water in strata equivalent to Bachu's (1995a) pre-Cretaceous mega-hydrostratigraphic group, and waters from Lower Cretaceous clastic aquifers (Group 2) were interpreted to be composed of evaporated seawater, that was subsequently diluted 50-80% by post-Laramide meteoric water, but has been isolated from further meteoric influences. Triassic to Upper Mississippian formation waters were not considered in the study mentioned above because the respective strata are eroded in the central part of the basin (Fig. 6.1b). It has to be investigated to what extent hydrogeological phenomena in the Tertiary-Cretaceous and Cambrian-Devonian hydrostratigraphic groups influence regional-scale fluid flow in the Jurassic-Mississippian strata in the study area and vice versa.

a.



b.

(after Bachu, 1995; 1999)

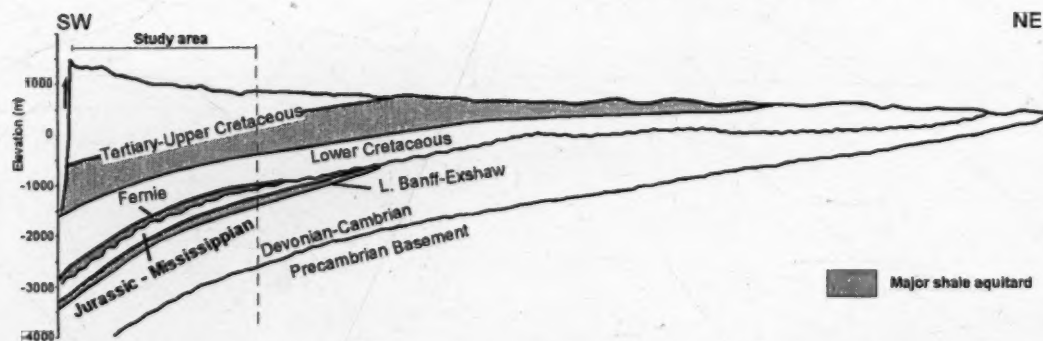


Figure 6.1: Location of the study area in the Alberta Basin: a) in plan view, showing main basin-scale flow systems identified previously by Hitchon et. al (1990), Bachu (1995a, 1997, 1999), and Anfort et al., 2001), and b) in cross-section showing major, basin-wide continuous aquitards.

Particular issues that need to be addressed are:

- (1) The hydraulic competence of the Fernie aquitard at the top of the Jurassic-Mississippian hydrostratigraphic group has to be characterized, in order to identify whether cross-formational flow is responsible for the high salinities observed in parts of the Lower Mannville aquifer (see Chapter 5).
- (2) Former regional hydrogeological studies in the Peace River Arch region (Hitchon et al., 1990; Bachu and Underschultz, 1992) and southwestern Alberta (Bachu and Underschultz, 1995), which covered parts of the study area, considered the Jurassic-Mississippian succession as a single, hydraulically continuous aquifer system. A finer resolution of the hydrostratigraphy is required to better understand the regional flow patterns in this part of the Alberta Basin.
- (3) What are the hydrochemical characteristics of the Jurassic-Mississippian formation waters in the study area?
- (4) Do "deep basin" hydrocarbon accumulations exist in the Jurassic-Mississippian hydrostratigraphic group similar to or as a continuation of, the ones in the overlying Mannville aquifers, as proposed by Masters (1984)?

6.2 Hydrostratigraphic framework

Large parts of the Triassic-Mississippian strata were eroded in the study area, and these sediments subcrop below the Jurassic, which complicates the assignment of lateral continuous hydrostratigraphic units. The Jurassic Fernie shales form a laterally continuous aquitard at the top of the Jurassic-Mississippian hydrostratigraphic group, whereas the shales of the Exshaw Formation, in conjunction with the shaly carbonates of the lower Banff Formation, represent the lower confining layer (Fig. 6.2).

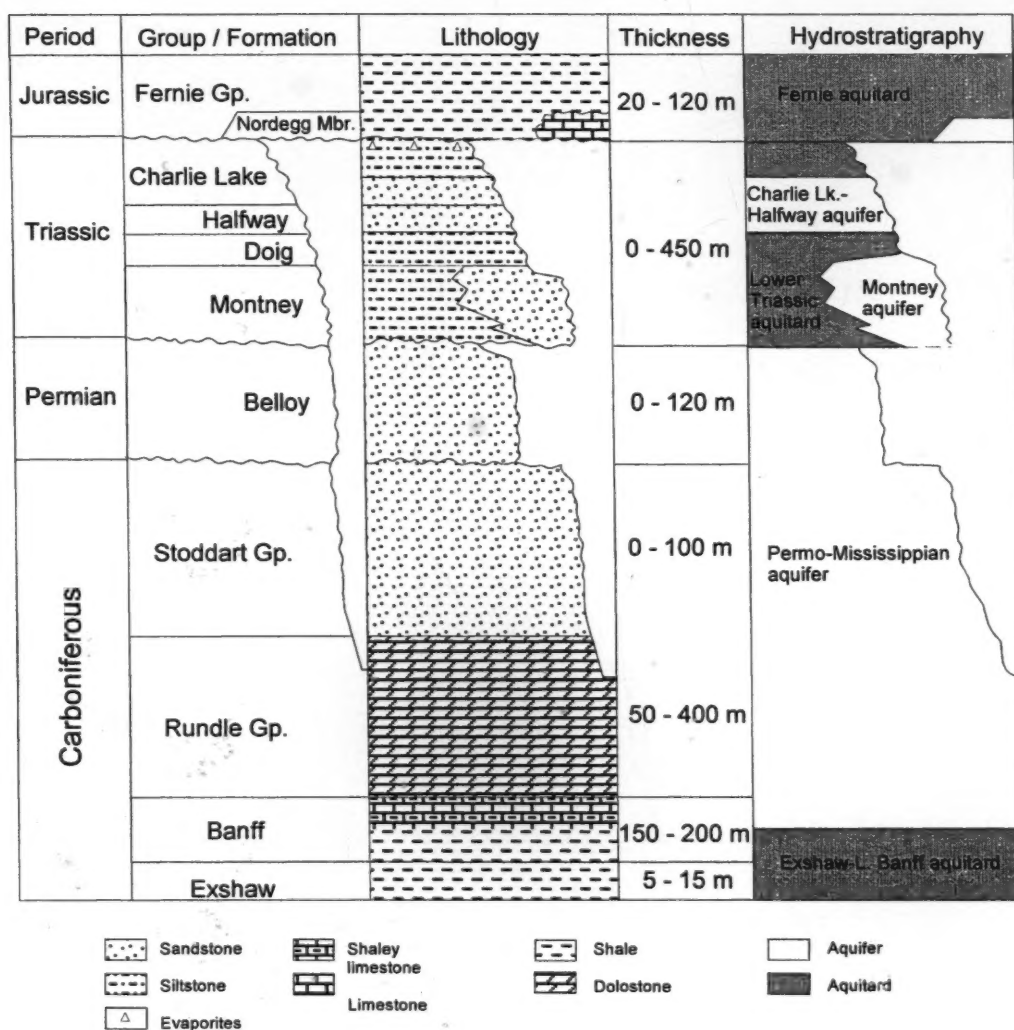


Figure 6.2: General lithology and hydrostratigraphy of the Jurassic-Mississippian succession in the study area.

The limestone aquifer of the Nordegg Member at the bottom of the Fernie Group is only present in the east, where it forms a continuous aquifer system with the underlying sediments of either the Montney Formation, the Belloy Formation or the Rundle Group (Fig. 6.3).

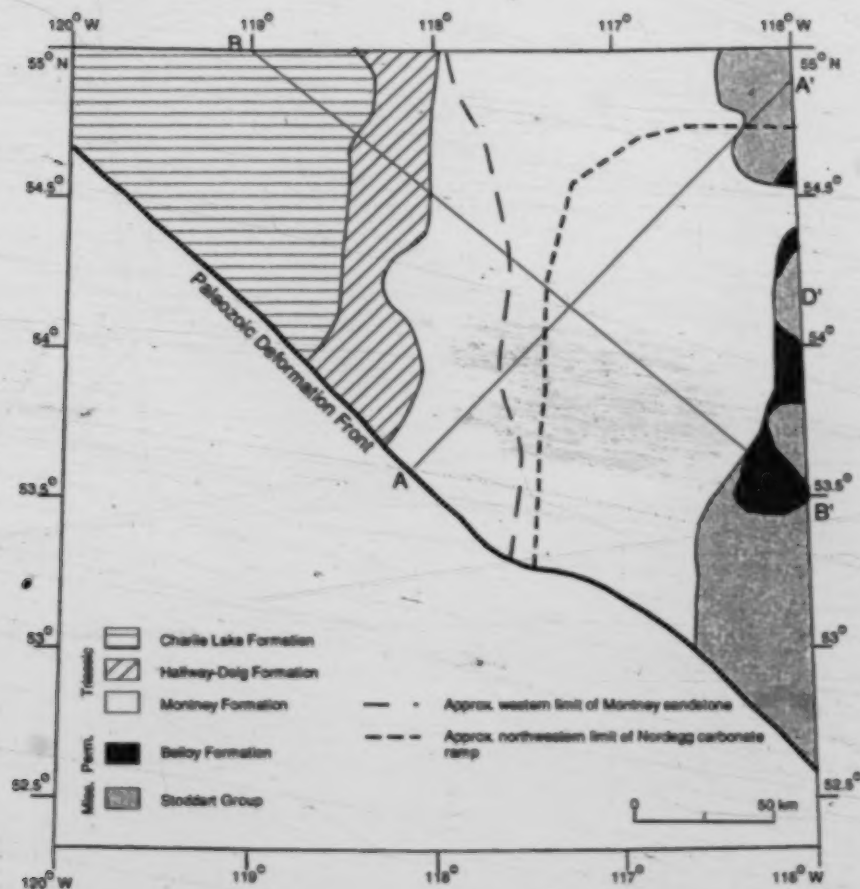


Figure 6.3: Erosional limits of Mississippian to Triassic strata below the Jurassic Fernie Group and limits of the depositional facies of the Montney sandstone (modified from Edwards et al., 1994) and the Nordegg limestone (modified from Poulton et al., 1990). See also Figure 4.7a in Chapter 4, which shows the areal extent of the Triassic and Permian sediments only.

The Triassic Charlie Lake, Halfway, and Doig Formations subcrop below the Fernie shales in the western half of the study area. The shales and minor evaporites in the upper part of the Charlie Lake form an aquitard as a vertical continuation of the Fernie aquitard. The sandstones in the Lower Charlie Lake and Halfway formations represent an aquifer, whereas shales and siltstones in the underlying Doig Formation form another aquitard. The general lithology in the Triassic Montney Formation changes from sandstones in the

eastern half of the study area to siltstones and shales towards the west (Edwards et al., 1994). Therefore, the Montney Formation successively develops westward into an aquitard, the boundary between aquifer and aquitard zone not being well defined. The Carboniferous Rundle and Stoddart groups consist of dolostones and sandstones, respectively, and form a continuous aquifer with the overlying sandstones of the Permian Belloy Formation.

The hydrostratigraphy in the Jurassic-Mississippian succession is different in the western and eastern halves of the study area. In the east, the Montney aquifer, which includes the Nordegg Member, is for most part in direct hydraulic communication with the underlying Permo-Mississippian aquifer, forming a continuous single Lower Jurassic-Mississippian aquifer. In the west, the Doig-Montney aquitard separates the Permo-Mississippian and Charlie Lake-Halfway aquifers. Therefore, the hydrogeological data are presented separately for the Charlie Lake-Halfway, the Montney and the Permo-Mississippian aquifers. This way, it is also easier to distinguish between possible influences (i.e., cross-formational flow) of hydrogeological phenomena in the overlying Mannville and the underlying Wabamun aquifers on fluid and pressure distributions in the Jurassic-Mississippian hydrostratigraphic group.

6.3 Hydrogeological patterns

Similar to the hydrogeology of the Tertiary-Cretaceous succession (Chapter 5), contour maps of equivalent hydraulic heads, and $p(d)$ - and $p(z)$ -plots were used to interpret the flow in the Jurassic-Mississippian succession. Formation water density ranges between approximately 1000 and 1080 kg/m³, and an average reference density $\rho_0 = 1040$ kg/m³ was used to calculate hydraulic heads in order to minimize the DFR and to be able to analyze the flow using hydraulic heads only (see Chapter 2). Maps of salinity and bicarbonate distributions were used in the hydrochemical analysis. The respective ranges

of hydraulic head and salinity values for the Jurassic-Mississippian hydrostratigraphic group and adjacent aquifers are presented in Table 6.1.

Aquifer	H_0 ($\rho_0 = 1040 \text{ kg/m}^3$)	TDS
Lower Mannville	400 – 600 m	35 – 90 g/l
Charlie Lake-Halfway	415 – 550 m	115 – 160 g/l
Montney	450 – 650 m	50 – 155 g/l
Permo-Mississippian	500 – 700 m	50 – 165 g/l
Wabamun	570 – 950 m	120 – 260 g/l

Tab. 6.1: Summary of ranges in hydraulic head and salinity in the Jurassic-Mississippian aquifers. Values for the adjacent Lower Mannville and Wabamun aquifers are listed for reference. Hydraulic heads are calculated with the same reference density of 1040 kg/m^3 and their distribution is shown in Figures 6.4 & 6.5 for comparison purposes.

The distribution versus depth of all the pressure data indicates that the aquifers in this succession are underpressured (Fig. 6.6a). The pressure distribution versus elevation, which fits almost entirely on a straight line (Fig. 6.6b), indicates that the Permo-Mississippian and Montney aquifers are in good hydraulic communication, except for a hydrocarbon-saturated low in the Montney aquifer. The distribution of pressure data from the Charlie Lake-Halfway aquifer, present only in the northwest, confirms that this aquifer is not in hydraulic communication with the other aquifers in the succession, as inferred also on the basis of lithology and facies distribution (Figs. 6.2 and 6.3). Similarly, the underpressured hydrocarbon-saturated zone in the Montney aquifer seems to be poorly connected with the surrounding water-saturated zone (Fig. 6.6b).

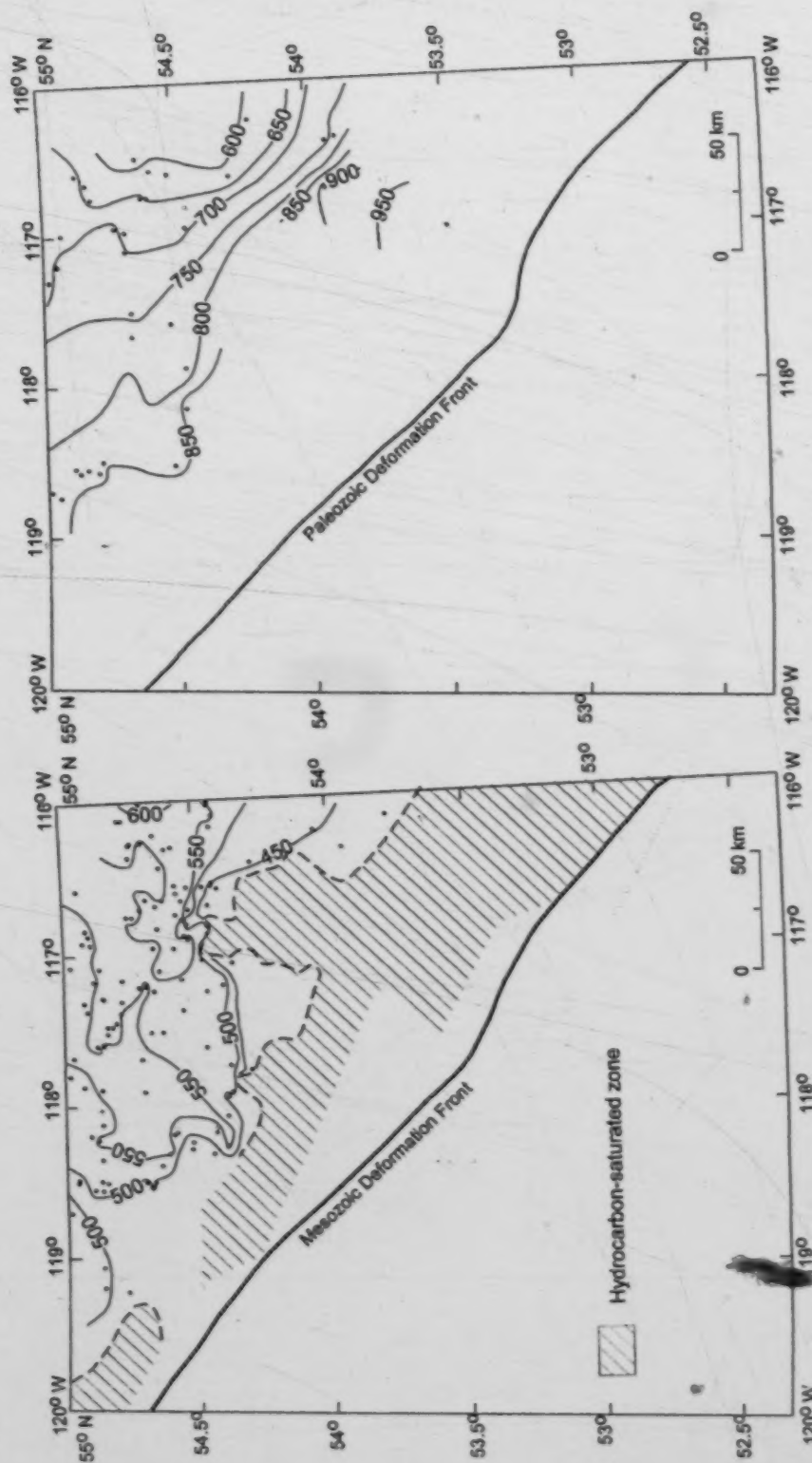


Figure 6.4: Hydraulic head distribution in the Lower Mannville aquifer ($\rho_0 = 1040 \text{ kg/m}^3$, 50 m contour interval).

Figure 6.5: Hydraulic head distribution in the Wabamun aquifer ($\rho_0 = 1040 \text{ kg/m}^3$, 50 m contour interval).

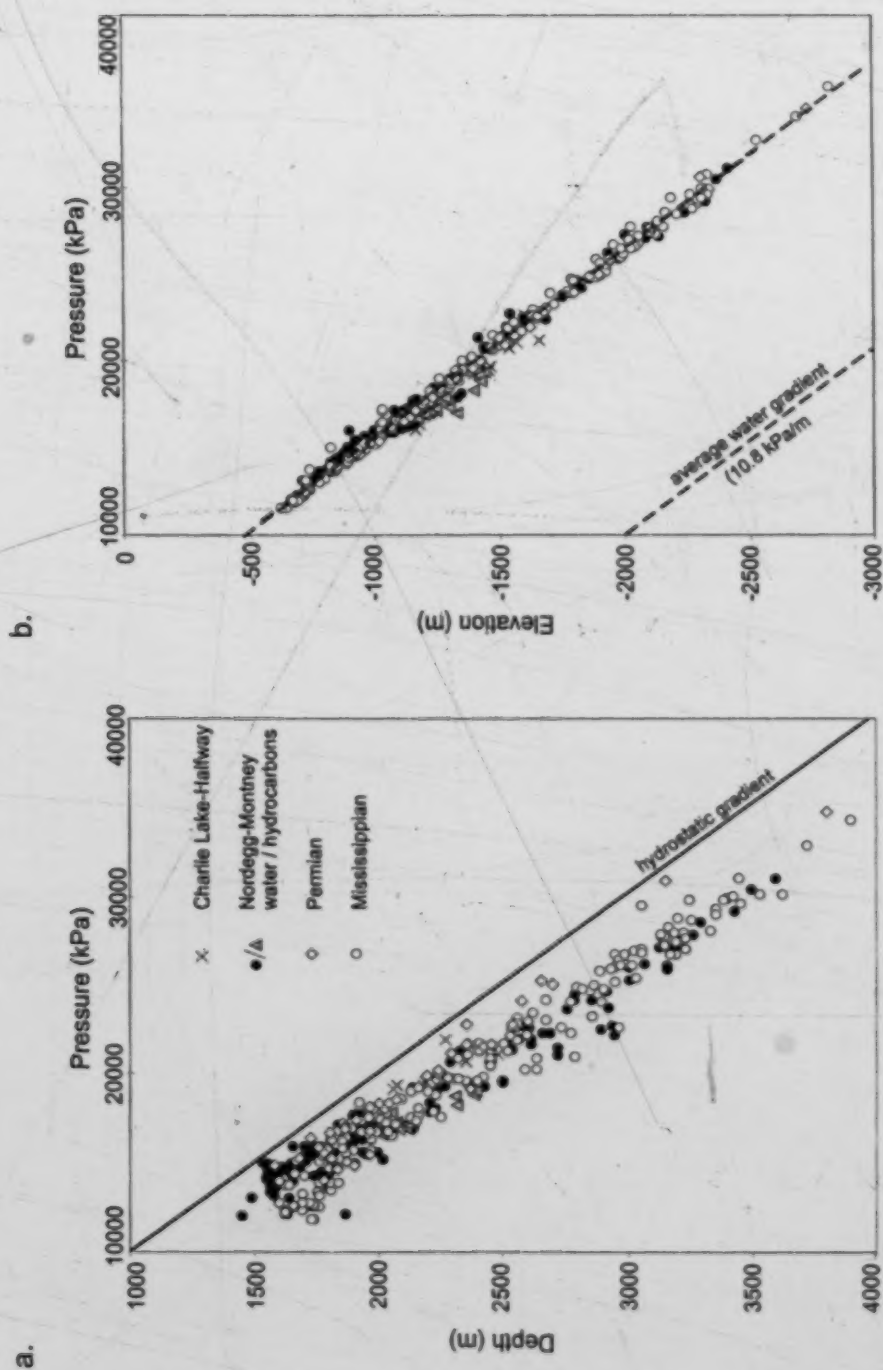


Figure 6.6: Variation of pressure with: a) depth, and b) elevation, for the Jurassic-Mississippian aquifers in the study area.

Triassic aquifers

Figures 6.7 to 6.9 present, respectively, the distribution of hydraulic heads, salinity and bicarbonate in the Charlie Lake-Halfway and Montney aquifers. Because of the location of its subcrop edge, the extent of the Charlie Lake-Halfway aquifer is limited to the northwestern corner of the study area and, therefore, the hydrogeological data are sparse. For better comparison, both aquifers are shown on the same map, because each is confined at the top by the Fernie aquitard. Fluid pressures plot slightly sub-hydrostatic and generally above those of the Montney aquifer at comparable depths (Fig. 6.6a). Hydraulic heads in the Charlie Lake-Halfway are generally at the lower end of the data range in the Triassic aquifers (Fig. 6.7), and the salinity ranges between 115 - 150 g/l (Tab. 6.1).

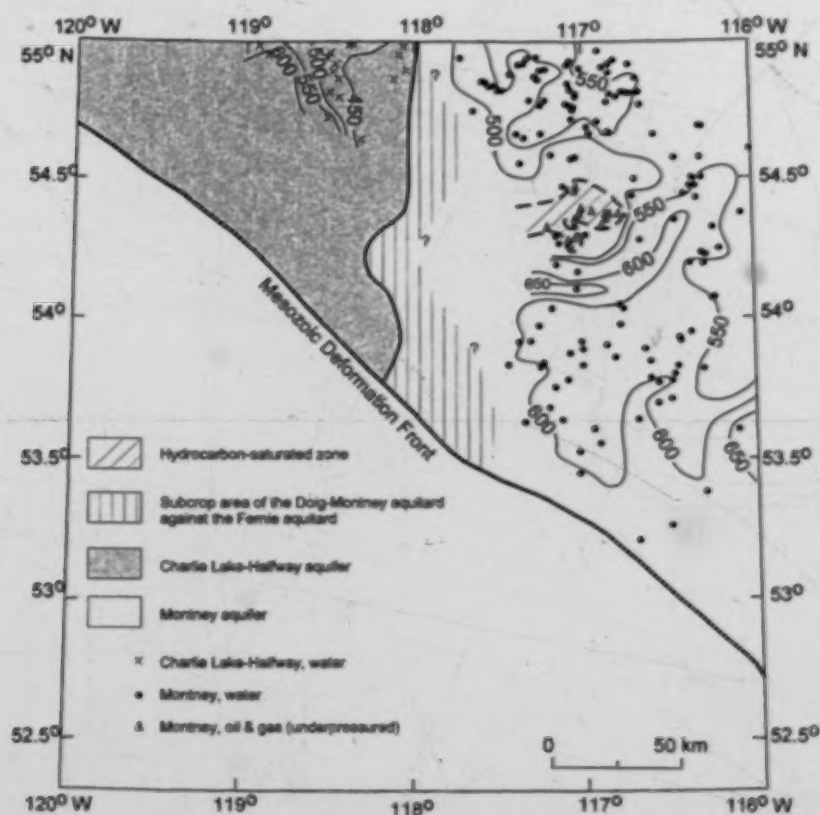


Figure 6.7: Hydraulic head distribution in the Charlie Lake-Halfway and Montney aquifers (50 m contour interval, H calculated with $\rho_0 = 1040 \text{ kg/m}^3$).

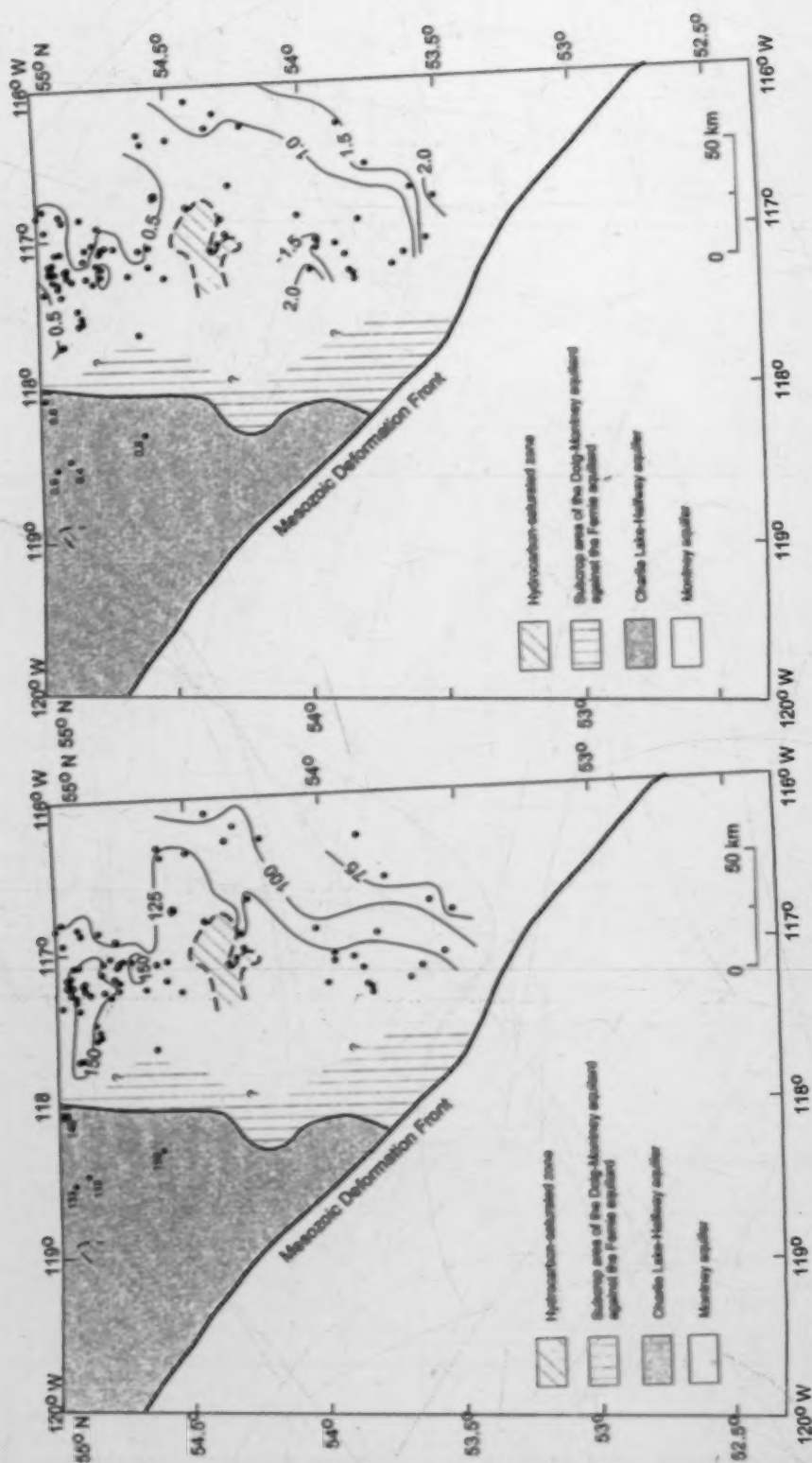


Figure 6.8: Salinity distribution in the Triassic aquifers (25 g/l contour interval in the Montney aquifer, point values in the Charlie L.-Halfway aquifer). Boundaries correspond to zonation in Figure 6.7.

Figure 6.9: Bicarbonate distribution in the Triassic aquifers (0.5 g/l contour interval in the Montney aquifer, point values in the Charlie L.-Halfway aquifer). Boundaries correspond to zonation in Figure 6.7.

Hydraulic heads in the Montney aquifer generally range between 650 and 450 m, and in the north they decrease inwards, towards the centre of the study area. At approximately 117° W and 54° N, a tongue of hydraulic heads > 600 m forms a potential high, from which hydraulic head values decrease towards the center and northeastward (Fig. 6.7). Flow appears to be focused into a region with hydraulic heads of 450 m, which is adjacent to a hydrocarbon-saturated zone in which fluid pressures plot slightly below the average water gradient (Fig. 6.6b). Lack of data along the northwestern part of the deformation front and towards the center makes it difficult to tell whether the hydrocarbon-saturated zone is closed in that area or if it continues further towards the deformation front.

The salinity in the Montney aquifer increases from 50 g/l in the southeast to 155 g/l in the north (Fig. 6.8). Generally, the lower salinity waters have relatively high bicarbonate concentrations (Fig. 6.9).

Permo-Mississippian aquifer

Figures 6.10 to 6.12 present, respectively, the distribution of hydraulic heads, salinity and bicarbonate in the Permo-Mississippian aquifer. Hydraulic heads decrease from approximately 700 m in the southeast corner of the study area to almost 500 m at the northern boundary (Fig. 6.10). A relatively steep hydraulic gradient can be observed in the southeastern and northeastern corners, and along 117° W, where hydraulic heads drop by approximately 100 m over a relative short distance (~ 10 km). On the other hand, in an approximately 50 km wide area sub-parallel to 116.5° W the hydraulic heads decrease northward by less than 100 m over a 150 km distance. The pressure distribution versus depth (Fig. 6.6a) indicates that the Permo-Mississippian aquifer generally is sub-hydrostatically pressured. In the p(z)-plot (Fig. 6.6b), pressure data follow a relatively straight line, which indicates good hydraulic communication within the aquifer.

The salinity of formation waters in the Permo-Mississippian aquifer generally increases northwestward in the direction of decreasing hydraulic heads from 50 to 150 g/l and the values stay relatively constant (~ 150 g/l) along the northern boundary of the study area (Fig. 6.11). A relatively abrupt salinity increase from 75 to 125 g/l can be observed northwestward from approximately 54° N at the eastern boundary parallel to the deformation front. Along approximately the same line the bicarbonate concentrations rapidly decrease from > 3 g/l in the southeast to < 1 g/l in the north (Fig. 6.12).

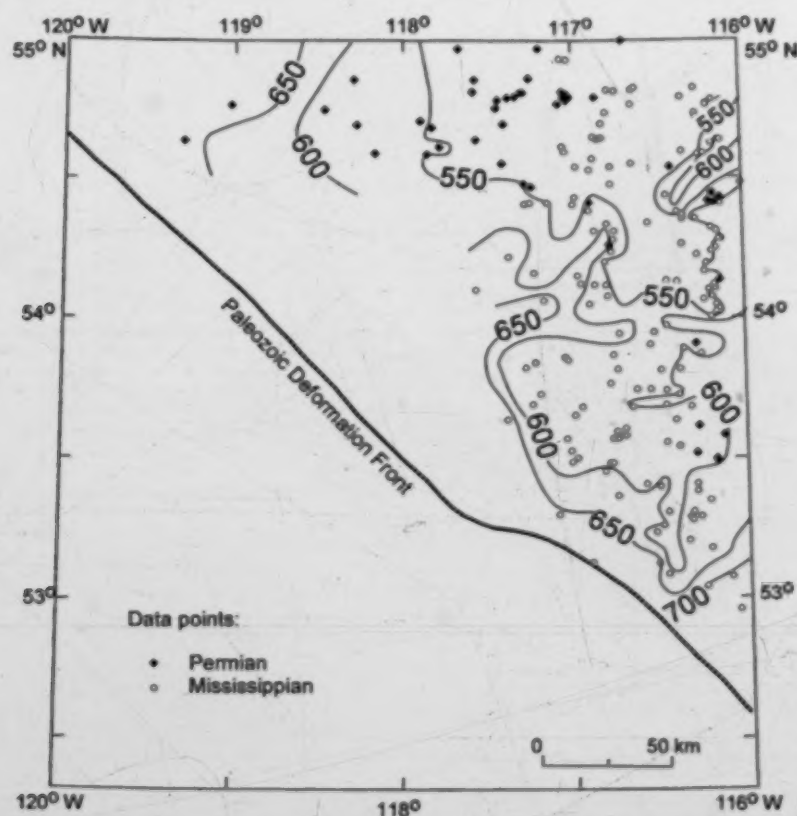


Figure 6.10: Hydraulic head distribution in the Permo-Mississippian aquifer (50 m contour interval, H calculated with $\rho_0 = 1040 \text{ kg/m}^3$).

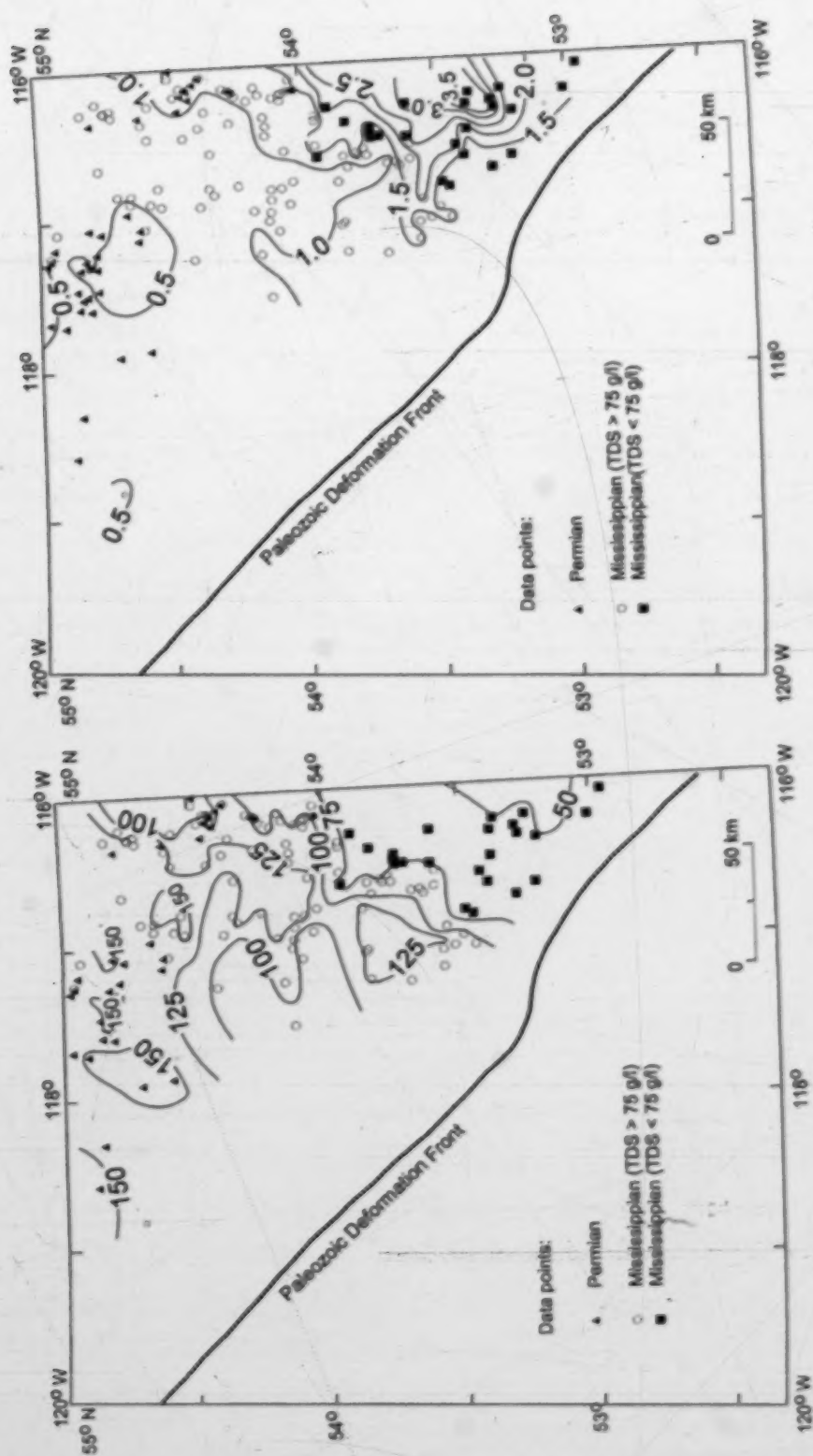


Figure 6.11: Salinity distribution in the Permo-Mississippian aquifer (25 g/l contour interval).

Figure 6.12: Bicarbonate distribution in the Permo-Mississippian aquifer (0.5 g/l contour interval).

Selected cations in the Jurassic-Mississippian formation waters

The Jurassic-Mississippian formation waters plot slightly enriched with respect to Na along the seawater-evaporation trajectory (SET) (Fig. 6.13a). The Triassic formation waters and the Mississippian waters from the northern part plot below the SET of Cl versus Br. On the other hand, the low-salinity Mississippian waters from the southeast plot above the SET (Fig. 6.13b).

All of the formation waters are significantly depleted in Mg with respect to the SET (Fig. 6.13c). Conversely, most of the formation waters are enriched in Ca, except for some of the low-salinity Mississippian waters from the southwestern part of the study area, for which concentrations plot below the SET (Fig. 6.13d).

Summary of hydrogeological observations

- The hydrostratigraphy of the Jurassic-Mississippian succession and the hydraulic head distribution are different in the western and eastern halves of the study area, approximately W and E of 118° W, respectively.
- Hydraulic heads in the Charlie Lake-Halfway aquifer decrease towards the east, whereas they generally decrease northward in the Montney and Permo-Mississippian aquifers, with the exception of a hydraulic-head low in the center of the Montney aquifer.
- Hydraulic heads less than 500 m in the center of the Montney aquifer indicate a fluid sink, which is not present in the underlying Permo-Mississippian aquifer.
- Generally, the salinity of formation waters in the eastern half of the study area increases northward in the direction of decreasing hydraulic heads in the entire succession.
- There is a zone in the deeper parts of the Triassic aquifers that is saturated with underpressured oil and gas in the Montney aquifer.

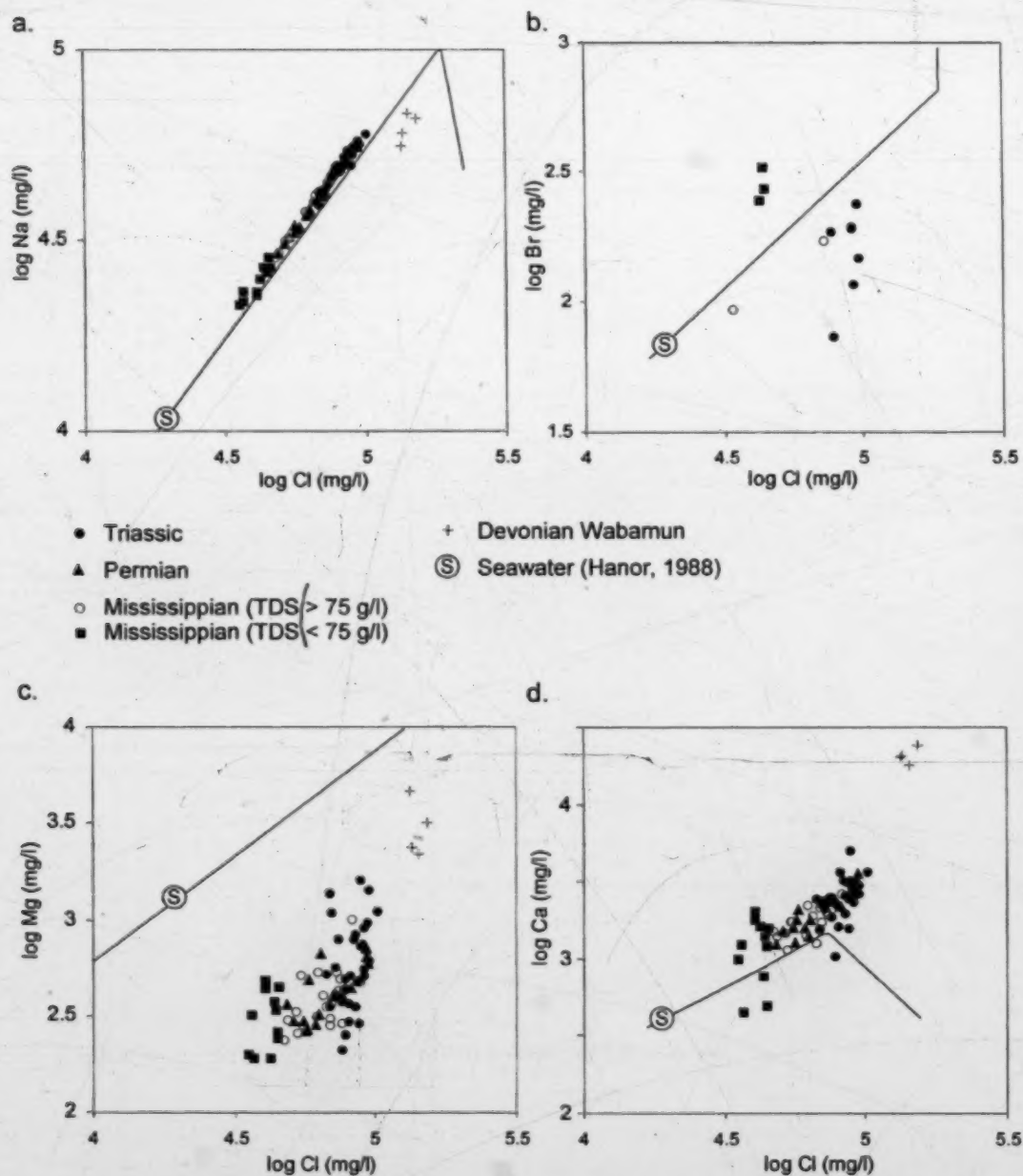


Figure 6.13: Cross plots versus chloride of: a) sodium, b) bromide, c) magnesium, and d) calcium for formation waters in the study area from the Jurassic-Mississippian succession and from the underlying Devonian Wabamun aquifer. Analyses indicating dilution by meteoric water (TDS < 75 g/l) are distinguished from the presumably connate waters. The black line on figures a, b, c, and d represents the respective seawater evaporation curves experimentally determined by McCaffrey et al. (1986).

6.4 Interpretation of flow patterns

Aquitard competence and lateral barriers to flow

The confining Fernie aquitard at the top of the Jurassic-Mississippian hydrostratigraphic group thins from 100 m along the deformation front to less than 20 m in the northeastern corner. It separates the overlying Lower Mannville aquifer (Chapter 5) from the Charlie Lake-Halfway and Montney aquifers in the western and eastern halves of the study area, respectively. The Fernie shales are considered to be an effective, regional-scale aquitard in the western Alberta Basin, but they are completely eroded northeast of the study area (Bachu, 1995a).

In the northwestern corner of the study area, the $p(z)$ -plot (Fig. 6.14a) suggests the possibility of cross-formational flow from the Charlie Lake-Halfway aquifer into the Lower Mannville aquifer, which would explain the increased salinity in the Lower Mannville in that area (Fig. 5.26, Chapter 5). Here the Charlie Lake-Halfway aquifer terminates against the Fernie aquitard and the otherwise eastward lateral flow along the Doig aquitard probably is forced upwards into the Lower Mannville aquifer as shown in the hydrogeological cross section (Fig. 6.15). Higher hydraulic heads in the underlying Montney aquifer east of the subcrop edge suggest that flow does not continue sublaterally across the Doig aquitard and along the base of the Fernie aquitard.

In the southern half the competence of the Fernie aquitard can be inferred from the different fluid saturations in the Lower Mannville (gas) and Montney (water) aquifers. In addition, the offset of fluid pressures in the Lower Mannville and Montney aquifers in the $p(z)$ -plot in Figure 6.14c suggests that there is no hydraulic communication between both aquifers. On the other hand, near the center of the study area the pressure and fluid distributions above and below the Fernie aquitard are similar (Fig. 6.14b), and the "deep basin" gas accumulation in the Lower Mannville aquifer appears to vertically continue into the Montney aquifer.

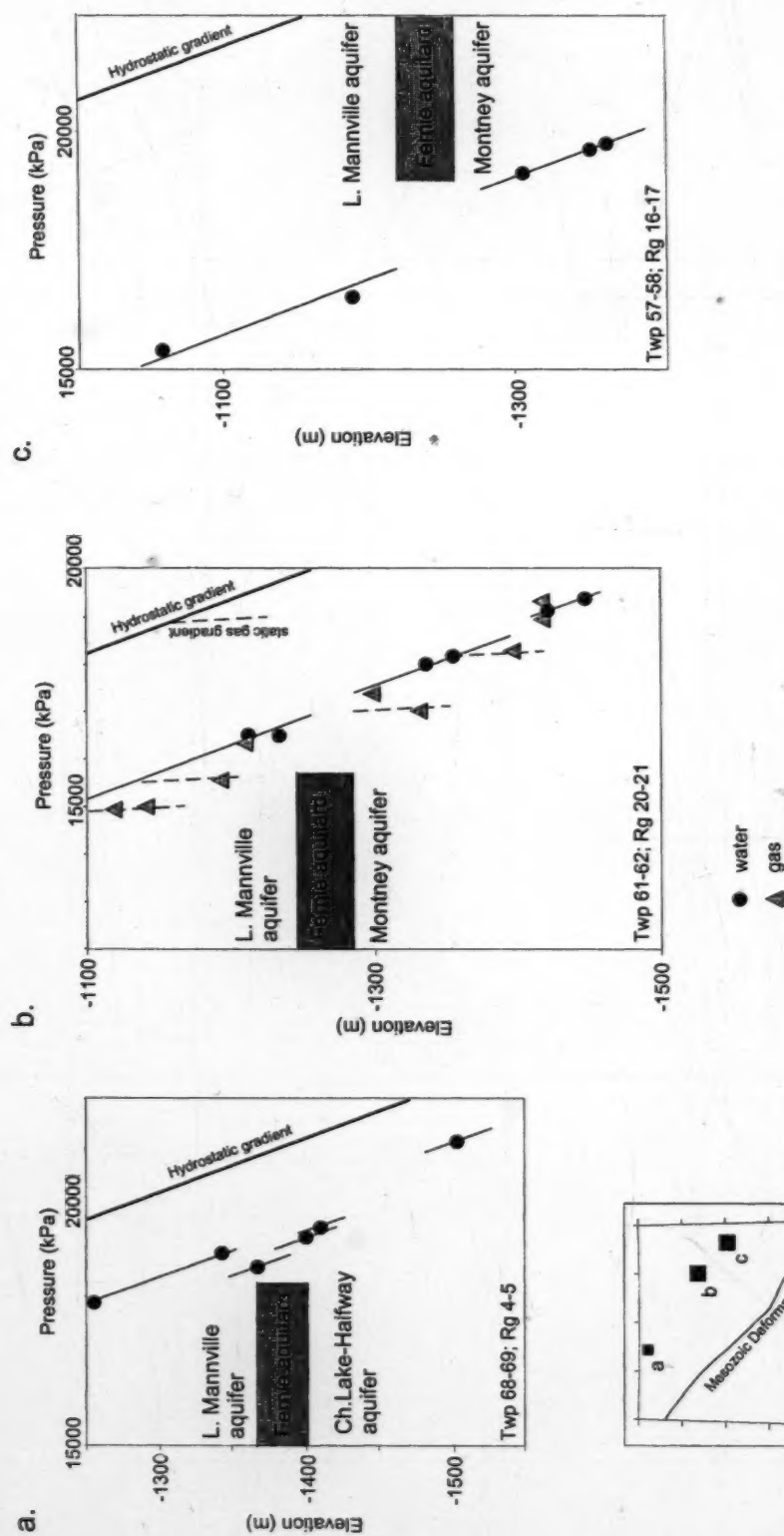


Figure 6.14: Pressure-elevation plots across the Fernie aquitard for the Lower Mannville and Triassic aquifers in various regions of the study area.

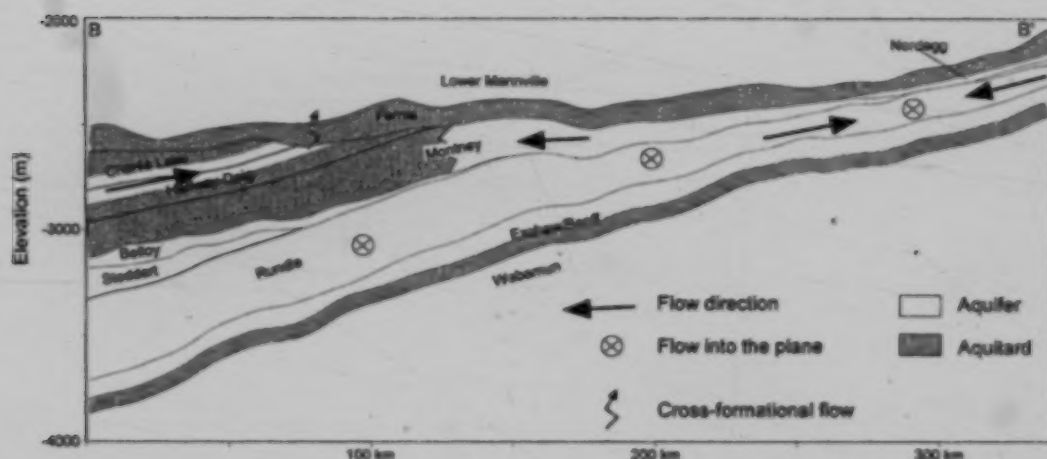


Figure 6.14: Hydrogeological cross section (B - B') sub-parallel to the deformation front showing inferred flow patterns in the Mississippian-Jurassic succession. See Figure 6.1 for line of cross section.

Lack of pressure data towards the deformation front prevents a detailed mapping of this gas-saturated zone in the Montney aquifer. Apparently, the gas-saturated zone does not continue further down into the directly underlying, water-saturated Permo-Mississippian aquifer, which also suggests that there exists a barrier to flow between the latter and the Montney aquifer in that region.

In the northeastern corner of the study area, where the Triassic (and the Permian) strata are eroded and the Nordegg Member consists of carbonates, only approximately 20 m of Ferne aquitard lie between the Lower Mannville and the Mississippian. The hydraulic head distributions in both aquifers are similar (Figs. 6.4 & 6.10) and values decrease westward from above 600 m to less than 550 m, indicating flow from east of the study area. On the other hand, the hydraulic gradient in the Permo-Mississippian aquifer is slightly steeper than in the Lower Mannville aquifer, so that only along a narrow band at the eastern boundary of the study area, flow in the Lower Mannville and Permo-Mississippian aquifers appears to merge. This does not necessarily infer cross-formational

flow, which would disagree also with the different salinities in both aquifer (Figs. 5.26 and 6.11, but rather is the reflection of a regional SE-NW directed flow system in a continuous Mississippian-Jurassic-Mannville aquifer (Bachu, 1995a, Anfort et al., 2001) extending into the study area from the east, where the Fernie shales are eroded.

The decreasing permeability in the Montney Formation towards the west is inferred from a change in lithology from sandstone to siltstones and shales (Edwards et al., 1994). This is indirectly confirmed by the lack of hydrogeological data in the western part of the Montney Formation, suggesting that this area does not contain substantial reservoir units. The low-permeability part of the Montney Formation also forms an aquitard with respect to flow in the underlying Permo-Mississippian aquifer. In addition, the gas-saturated zone in the Montney aquifer appears to lie in the transition zone from high-to-low permeability, and to be confined at its base (Fig. 6.16), because it is not affected by formation water flow in the underlying Permo-Mississippian aquifer.

Generally, the hydraulic head and salinity distribution in the Permo-Mississippian and Montney aquifers are very similar, except for the hydraulic low associated with the gas-saturated zone in the Montney aquifer. In addition, the pressure variation with elevation in the Montney and Permo-Mississippian aquifer is very similar, as pressure data from both aquifers fall almost on the same straight line. Only in the vicinity of the hydrocarbon-saturated-zone (-1200 to -1500 m elevation) do pressures in the Montney aquifer plot slightly below the line defining the average water gradient in both aquifers (Fig. 6.6). This shows that the Mississippian-to-Lower Jurassic strata form a hydraulically continuous aquifer system in the eastern half of the study area.

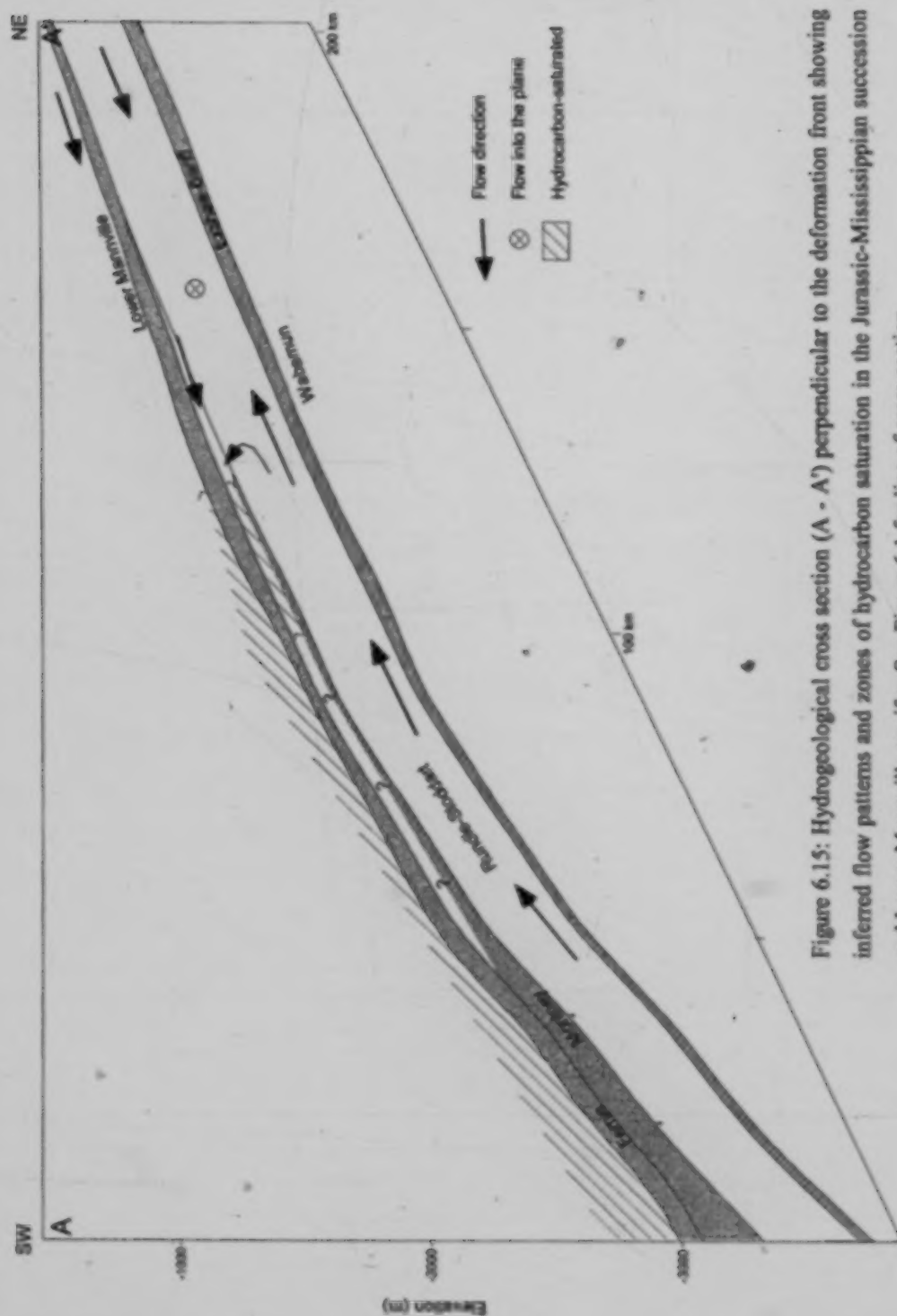


Figure 6.15: Hydrogeological cross section (A - A') perpendicular to the deformation front showing inferred flow patterns and zones of hydrocarbon saturation in the Jurassic-Mississippian succession and Lower Mannville aquifer. See Figure 6.1 for line of cross section.

The Exshaw-Banff aquitard at the base of the succession is considered to be a strong, basin-wide aquitard (Bachu, 1995a). This is confirmed in the study area by lower hydraulic heads in the Permo-Mississippian aquifer (Fig. 6.10) compared to the underlying Wabamun aquifer (Fig. 6.5). The difference in hydraulic heads between the Permo-Mississippian and the Wabamun aquifers is largest along the deformation front in the deeper parts of the aquifers. The difference decreases northeastward along dip, until hydraulic heads are in the same range in the northeast corner of the study area, where pressures in the Permo-Mississippian and the Wabamun aquifers appear to have equilibrated to similar boundary conditions. The analysis of hydrogeological data in the Devonian aquifers is necessary for a more detailed discussion on cross-formational flow across the Exshaw-Banff aquitard and the reader is referred to Chapter 7.

Fluid origin and evolution

The Mississippian to Jurassic sediments were deposited mainly in a marine environment, therefore, the original formation water most likely consisted of seawater. The slight excess in Na concentrations compared to evaporated seawater (Fig. 6.13a) and the Br/Cl systematics (Fig. 6.13b) suggests that, in addition to seawater evaporation, the salinity of Mississippian-Jurassic formation waters has been influenced significantly by subsequent evaporite dissolution, for which Charlie Lake Fm evaporites in the northwest of the study area are the main potential source (Kirste et al., 1997).

Mississippian carbonates are largely dolomitized, and therefore replacive dolomitization of limestone is probably the main cause for the depletion of Mg and, at least partly, for the enrichment in Ca in the formation waters. Lewchuk et al. (1998) interpreted the replacive dolomites in Mississippian carbonates in southern Alberta as early diagenetic products that were precipitated along with evaporites from Mg-rich brines during Mississippian time. The exact composition of these brines is not known; however, Ca-ions replace Mg-ions in the formation water in a 1:1-ratio during the replacive

dolomitization of limestone, and the Ca/Mg-ratio should increase, following the 'dolomitizing' trend in Figure 6.17a. The actually observed positive correlation between Mg and Ca suggests that additional processes must have been involved that led to the chemical composition of formation waters presently observed in the Jurassic-Mississippian succession. The positive correlation of Ca and sulfate (Fig. 6.17b) indicates that gypsum dissolution partly contributed to the Ca content of the formation waters. Higher sulphate concentrations in the Triassic and Permian than in the Mississippian waters probably are related to the distance from the main evaporite deposits in the Triassic succession.

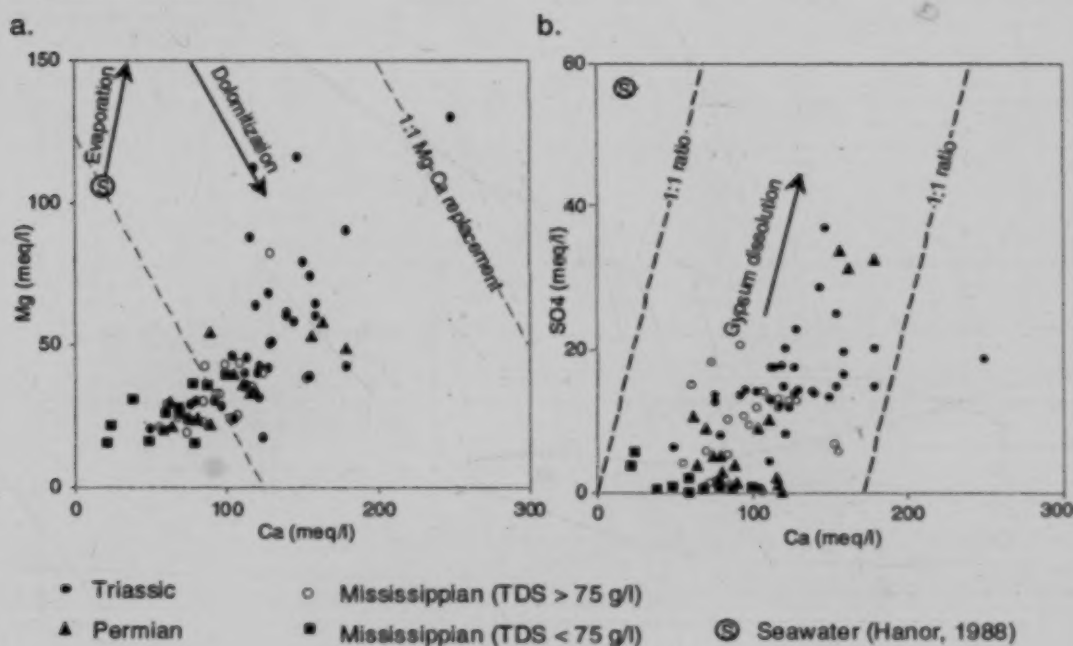


Figure 6.17: Cross plots of calcium versus: a) magnesium, and b) sulfate, for formation waters in the study area from the Jurassic-Mississippian succession.

Ca_{excess} versus Na_{deficit} values of Mississippian-Triassic formation waters in the study area plot around the Basinal Fluid Line (Davisson and Criss, 1996), but there is no distinct 2:1 correlation between Na and Ca that would confirm the albitization trend (Trend 1 in Fig. 6.18). Almost all water samples show excess in Na (negative Na_{deficit}) and a deficit-to-excess in Ca. Evaporation of seawater causes the Ca_{excess} values to decrease without

changing the Na component until the point of halite saturation (following Trend 2a beyond the lower boundary of Figure 6.18). During the precipitation of halite, the Ca_{excess} value stays constant and the Na_{deficit} value increases (Trend 2b). Obviously, the evaporation of seawater alone could not have produced the observed brine composition. However, during the dissolution of halite Na and Cl ions are added to the formation water in a 1:1-ratio, which causes a relative increase in Na over Ca (Trend 3). The dissolution of gypsum and the replacive dolomitization of limestone both cause an increase in Ca without effecting the Na and Cl concentrations (Trend 4).

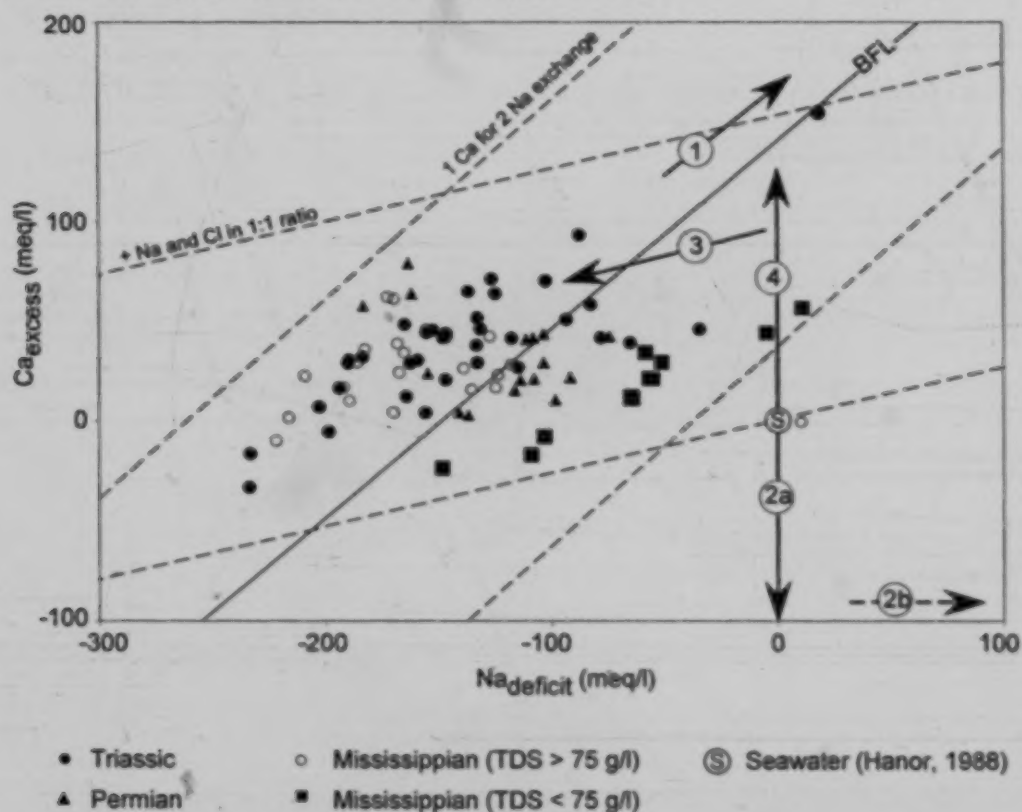


Figure 6.18: Plot of Ca_{excess} - Na_{deficit} for Mississippian-Jurassic formation waters in the study area, showing trends for various processes that may have effected the fluid composition. The circled numbers in the figure refer to the trends of: 1) albitization of plagioclase, 2) evaporation of seawater (a) beyond the point of halite saturation (b), 3) halite dissolution, and 4) dolomitization and gypsum dissolution. The Basinal Fluid Line (BFL) from Davisson and Criss (1996) is shown for reference.

Plotting salinity variations of the Jurassic-Mississippian formation waters versus their Na/Cl-ratios (Fig. 6.19) allows distinguishing between two types of brines and suggests that they have been affected by different processes. Brine I comprises most of the Triassic and Permian, plus some of the Mississippian data, and is characterized by salinities between approximately 75 to 170 g/l and a relatively narrow range of Na/Cl-ratios between 0.875 to 0.95. The high salinities are probably due to the high degree of seawater evaporation, which actually reached beyond the point of halite saturation during the Late Triassic, exemplified by halite deposits in the upper part of the Charlie Lake Formation. The shift towards Na/Cl-ratios higher than observed in seawater probably is due to subsequent halite (Na/Cl=1.0) dissolution in the subsurface.

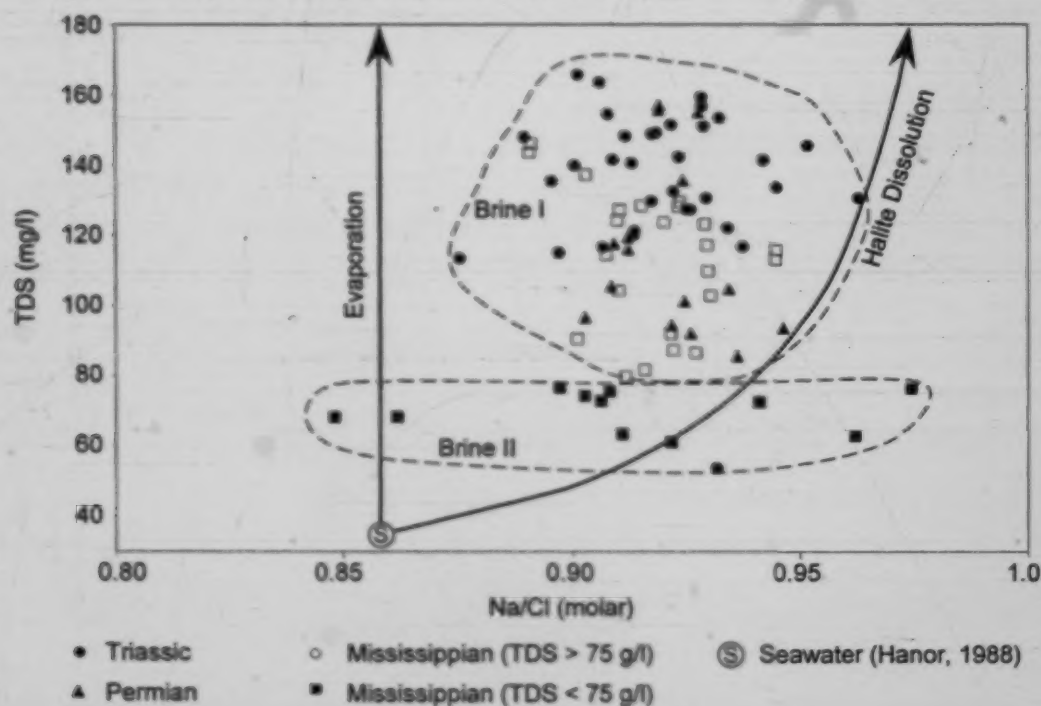


Figure 6.19: Na/Cl-ratio versus salinity plot of Jurassic-Mississippian formation waters showing tentative trends of evaporation and halite dissolution.

Brine II comprises exclusively Mississippian formation waters, mainly from the south- to southeastern part of the study area. These are relatively fresh waters (TDS = 50 - 75 g/l) with a wide spread in Na/Cl-ratios (0.85 - 0.98), which probably represent the mixing of evaporated seawater with water of more recent meteoric origin to the south of the study area. The degree of evaporation is significantly lower than for the Triassic formation waters, which is not surprising, as there are no significant evaporitic sequences deposited in the Mississippian strata in the study area.

Flow patterns and driving mechanisms

Flow in the Charlie Lake-Halfway aquifer, as inferred from hydraulic heads (Fig. 6.7), is eastward where the aquifer terminates against the Fernie aquitard. There it appears to be forced upwards into the Mannville aquifer, as hypothesized in the previous section. Flow could also be deflected northward along the subcrop boundary, but the hydraulic gradient inferred from the hydraulic head distribution north of the study area continues to suggest eastward flow (Hitchon et al., 1990) into the overlying Lower Mannville aquifer across the Fernie aquitard.

Flow in the north-central part of the Montney aquifer is directed inward, towards the hydrocarbon-saturated zone, and therefore differs from the general northward flow direction in the Montney and Permo-Mississippian aquifers. A fluid sink appears to exist in that region, which focuses flow and draws water from the Montney aquifer. The close association with the underpressured hydrocarbon-saturated zone suggests that this sink is created by a higher rate of hydrocarbon escape than hydrocarbon generation in that region, a mechanism that was described for the underpressured water in the overlying Lower Mannville aquifer (s. Chapter 5). The steep drop in hydraulic heads from 550 to less than 500 m in that area appears to delineate a lateral permeability barrier up to which the hydrocarbon-saturated zone probably extended during the period of deep burial and high rate of hydrocarbon generation. This rate decreased during uplift, allowing formation

water to re-imbibe the formerly hydrocarbon-saturated zone and causing the shrinkage of the latter, a trend that will probably continue with further basin uplift.

In the remainder of the combined Montney-Permo-Mississippian aquifer, hydraulic heads are high (> 600 m) along the eastern boundary and sub-parallel to the deformation front, and decrease towards the northwest and northeast, respectively. Therefore, the respective northwestern and northeastern flow directions merge into a northward flow direction in an approximately 50 km wide area sub-parallel to 116.5° W (Figs. 6.7 & 6.10). The steep hydraulic and salinity gradients in that area actually suggest that fresher formation water from the southeast and from the direction of the foothills region encloses a large plume of high-saline brine (TDS > 125 g/l) from all directions except from the north. This brine has a salinity approximately 4 times that of seawater (~ 35 g/l), and is contained within the ranges of brine I (Fig. 6.19). The hydraulic gradient within the area of the high-salinity brine is actually so low that, taking in account higher density brines in the shallow part of the aquifer in the north, and less than 50 m difference in hydraulic heads over a distance of 50 km in a northward direction, flow of brine I can only be inferred to be $\pm$ stagnant (see discussion on accuracy and resolution of hydraulic heads in Chapter 3; 3.3.4). The less saline water (brine II) coming from the south-southeast is most probably associated with a long-range, gravity-driven flow system originating in Montana (Bachu and Underschultz, 1995; Anfort et al., 2001). In the southeast, flow appears to be deflected by less permeable strata and forced to by-pass the high-salinity plume northwestward along the deformation front and northward along the eastern boundary of the study area, respectively. Because the Cretaceous aquitards and the hydrocarbon-saturated region in the overlying post-Jurassic succession represent a barrier to meteoric recharge from directly above, the southwestern component of the flow could alternatively be explained only by flow originating in the foothills region. In that case, the relatively low salinity could be due to meteoric recharge in the Rocky Mountains and subsequent downward flow along faults into the Mississippian to Jurassic strata, or caused by expelled water as the result of tectonic loading during the Laramide orogeny. Recharge in the thrust and fold belt, followed by a tortuous flow path, hydraulically connecting

deformed and undeformed Mississippian strata, has been proposed by Underschultz and Bartlett (1999) in the southern part of the study area. Their study was largely based on industry data not accessible to the public, and it is difficult to evaluate their results. Tectonic expulsion as a possible driving mechanism for regional-scale flow was first introduced theoretically by Oliver (1986), and was proposed to have affected flow in the Cambrian-Devonian hydrostratigraphic group (Bachu, 1995a; Machel and Cavell, 1999). However, considering the relatively low salinity of formation waters along the deformation front, a meteoric origin combined with a long-range, gravity-driven flow system seems to be the most likely explanation for the observed flow pattern in the Mississippian-Jurassic succession. A more detailed discussion on this topic follows in Chapter 7.

6.5 Summary and conclusions

In the eastern half of the study area, the Jurassic-Mississippian hydrostratigraphic group represents a single continuous carbonate-sandstone aquifer system, consisting of the Lower Jurassic Nordegg Member, the Triassic Montney Formation, the Permian Belloy Formation and the Mississippian Stoddart and Rundle Groups. The confining units are the competent Fernie and Exshaw-Banff aquitards at the top and base, respectively. The general flow direction is northward, and fresher water, which is part of a basin-scale, gravity-driven flow system originating at high formation outcrops in Montana, flows around and partly displaces a plume of connate brine.

The relatively high salinity, in the 130-150 g/l range, and low bicarbonate content (~0.5 g/l) of formation waters in the northern part of the area indicate a connate origin of these waters. Evaporation of seawater, short of halite saturation, probably took place shortly after sediment deposition, but the Ca-Na-Cl systematics suggest that successive halite and gypsum dissolution, and dolomitization had a more prominent influence in forming the Jurassic-Mississippian brines currently observed in the study area. The only positive

indication, based on Br, for a brine formed by the evaporation of seawater beyond the point of halite saturation was observed in the low-salinity brine in the southeast. However, no halite deposits exist in the Jurassic-Mississippian strata in this part of the Alberta Basin, and the source for the highly evaporated component in this supposedly highly diluted formation water must be located somewhere along the flow path in the southeast of the study area. A first comparison between the chemical signature of formation waters from the Jurassic-Mississippian and the underlying Wabamun suggest that these brines are different. A detailed discussion on the origin and evolution of formation waters from the entire stratigraphic succession follows in Chapter 8.

Only the Permo-Mississippian aquifer continues westwards, whereas the lithology in the overlying Montney Formation changes to siltstones and shales, which, in combination with the Doig Formation, form an aquitard. A "deep basin" hydrocarbon accumulation with relatively low hydraulic heads in its vicinity is observed in the transition zone from sand- to siltstones in the Montney Formation, similar to directly overlying hydrocarbon reservoirs in the Lower Mannville aquifer, but its exact areal extent is not known. Overlying the Doig-Montney aquitard is the Charlie Lake-Halfway aquifer. Flow in this aquifer is eastward and, at its subcrop edge, is forced upward through the Fernie shales into the Lower Mannville aquifer, where it causes an increase in formation water salinity.

No hydrocarbon-saturated zones were detected in the Permo-Mississippian aquifer, hence hydraulic communication of formation water between the deformed and undeformed parts of the Alberta Basin becomes possible at least from a fluid continuum point of view, but there are insufficient data to corroborate or disprove this. The hydraulic head distribution actually indicates that there is a component of flow from the direction of the thrust and fold belt of the Rocky Mountains, and the nature and origin of this flow will be further investigated in Chapter 7 for the underlying Cambrian-Devonian hydrostratigraphic group.

CHAPTER 7: FLOW OF FORMATION WATER IN THE CAMBRIAN-DEVONIAN SUCCESSION

7.1 Introduction

Earlier interpretations of the flow in the Alberta Basin suggested a basin-wide, topography-driven flow system that is recharged in the Rocky Mountain foothills in the southwest, channeled updip northeastward mainly along Devonian aquifers, and is discharged along the "feather-edge" of the basin (Hitchon, 1969a, 1984). This interpretation was used to explain the Pine Point Pb-Zn and the Athabasca oil sands deposits northeast of the study area (Garven, 1985, 1989). The main implication of the previous hydrogeological interpretation is that such a basin-scale flow system would have, at least partly, flushed the connate brines from the deep Devonian aquifers within 2 million years (Adams et al., 2000). Also, the flow in Devonian aquifers in the southwest is disconnected from meteoric recharge in the Rocky Mountains, and past tectonic compression was proposed as the mechanism that drives the flow in these aquifers (Bachu, 1995a).

The combination of mainly three mechanisms was proposed to have produced the brines in the Cambrian-Devonian succession in the Alberta Basin (Hitchon et al., 1971; Spencer, 1987; Connolly et al., 1990a): a) dissolution of evaporite deposits, b) evaporation of seawater, and c) shale membrane filtration. Hitchon et al. (1971) suggested that the dissolution of Middle Devonian halite is the major source for the high salinity in the Devonian brines, and that membrane filtration was responsible for further concentrating the brines. According to Spencer (1987) and Connolly et al. (1990a), evaporation of seawater is the main mechanism for the brine production; they argue that halite dissolution could not result in the bromide-chloride ratios observed in the Devonian

formation waters. On the other hand, according to Land (1987), it is possible to obtain Br-Cl ratios near or slightly greater than seawater from the recrystallization of halite.

The present study of formation water chemistry and flow patterns in Devonian aquifers in the vicinity of the Rocky Mountains deformation front in west-central Alberta (Fig. 7.1a) intends to identify the flow-driving mechanism(s) and to investigate whether there are indications for the displacement of connate brines in these aquifers. Elucidation of these issues is important for understanding hydrocarbon migration pathways and mineralization processes in the basin.

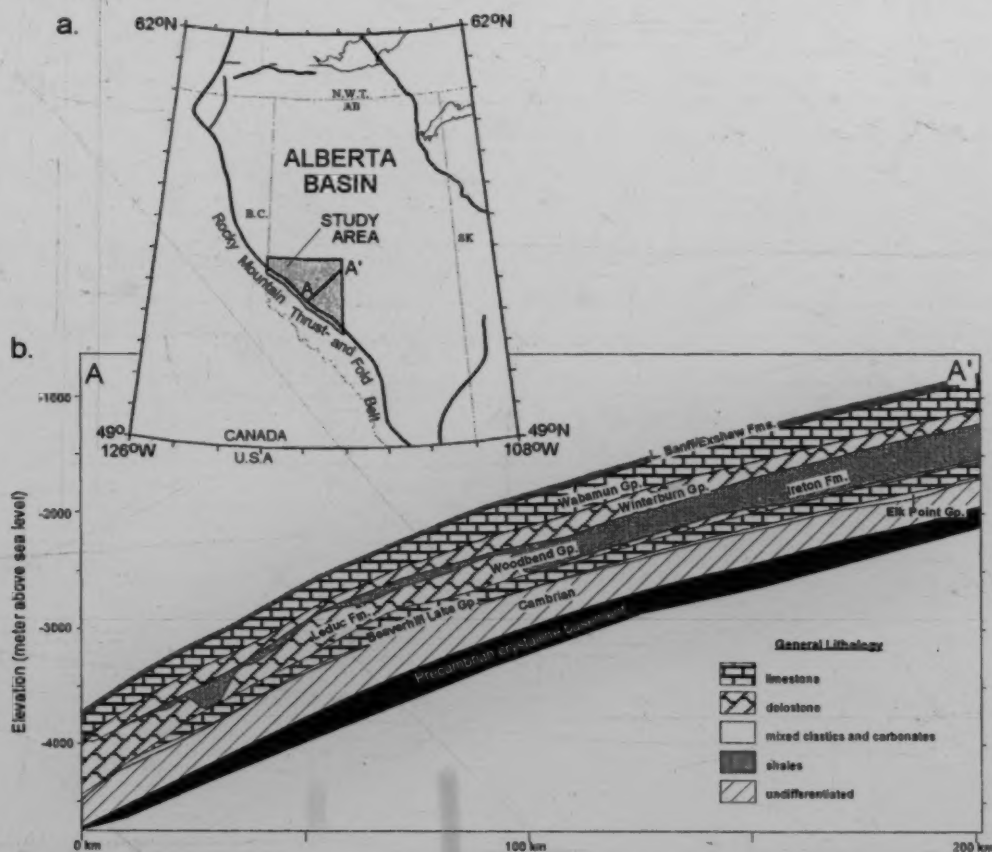


Figure 7.1: a) Location of the study area in the Alberta Basin and b) structural cross section perpendicular to the deformation front showing general lithology distribution in the Cambrian-Devonian succession.

7.2 Hydrostratigraphic framework

The Cambrian-Devonian succession in the study area lies 2000-5000 m below the ground surface, it has an average slope of 15 m/km, and consists mainly of marine carbonates and shales, approximately 1000 m in total thickness (Fig. 7.1b) that were deposited during the passive-margin stage of basin evolution (see Chapter 4). The Cambrian-Devonian hydrostratigraphic group is confined by the underlying crystalline Precambrian basement and the overlying Carboniferous shales of the Exshaw and Lower Banff Formations (Fig. 7.2), which form an aquiclude and an effective aquitard, respectively (Hitchon et al., 1990; Bachu, 1995a). The basal sandstones of Middle Cambrian age form a thin basal aquifer, which is separated from the Upper Cambrian carbonate aquifer by an intervening shale aquitard. In the northwest corner of the study area, where the Cambrian is absent due to non-deposition or erosion, the Devonian lies directly on the Precambrian basement (s. Chapter 4, Fig. 4.4 a). The Devonian succession is comprised, in ascending order, of the following groups: Elk Point, Beaverhill Lake, Woodbend, Winterburn and Wabamun (Fig. 7.2). Mixed near-shore clastics and carbonates of the Elk Point Group and the underlying Upper Cambrian form what, from now on, will be referred to as "Elk Point aquifer". It is overlain by the platform and reef carbonates of the Beaverhill Lake and Woodbend Groups that form the "Woodbend-Beaverhill Lake aquifer" (Fig. 7.1 b and Fig. 7.2). Along the Swan Hills and Cooking Lake platform edges, the intervening Watt Mountain and Waterways shales form local aquitards (Chapter 4, Fig. 4.4 b), where they separate the Elk Point, Beaverhill Lake and Woodbend aquifers, respectively. Thus, on a regional scale these aquifers act as a continuous aquifer system (Middle Devonian). The Woodbend Ireton shales constitute the major aquitard in the study area, separating the Woodbend-Beaverhill Lake aquifer from the overlying Nisku aquifer of the Winterburn Group. The Ireton aquitard thins considerably over several Woodbend Leduc reefs, and cross-formational flow at these locations is very likely, as identified in other parts of the Alberta Basin (Bachu and Underschultz, 1993; Rostron and Toth, 1997; Rostron et al., 1997; Anfort et al., 2001). The siltstones of the Winterburn Graminia Formation form a thin aquitard between the Winterburn and Wabamun aquifers, but these probably form a

rather continuous aquifer system (Upper Devonian) in most parts of the study area, as observed at the basin-scale (Bachu, 1995a). All shaly aquitards thin out southwestward near the deformation front, where the entire Devonian succession forms a single aquifer system (Skilliter, 1999).

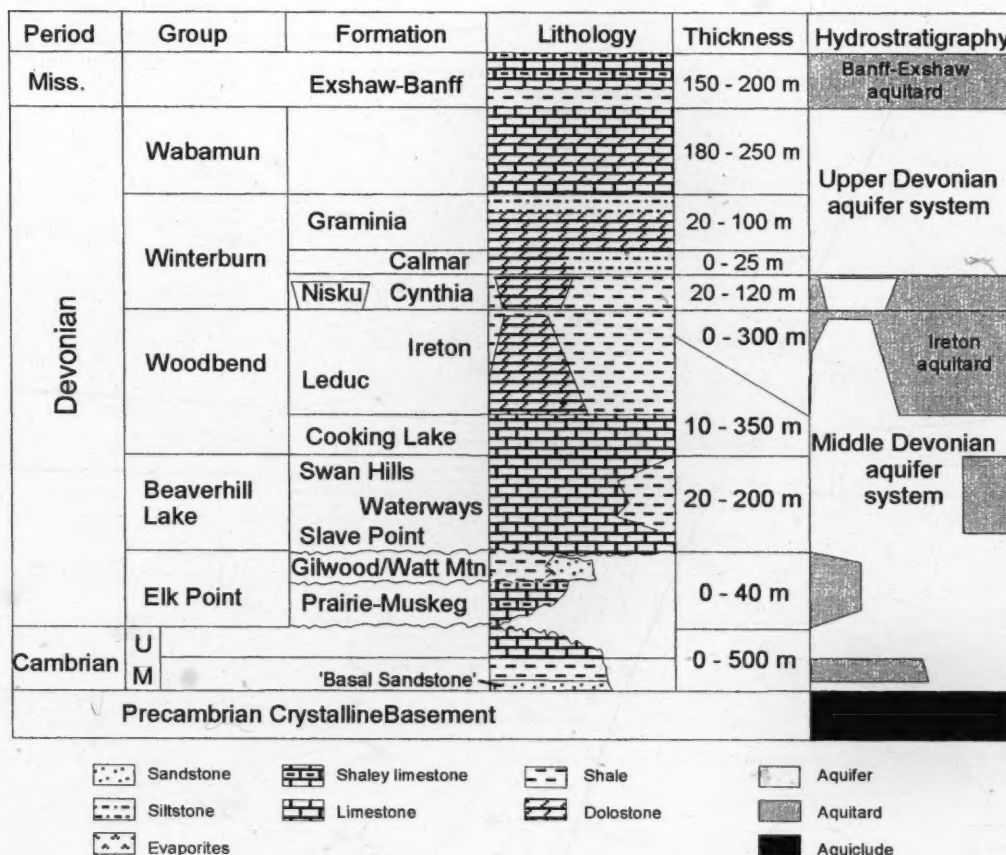


Figure 7.2: General lithology and hydrostratigraphy of the Cambrian-Devonian succession in the study area.

7.3 Hydrogeological Patterns

Contour maps of equivalent hydraulic heads, and $p(d)$ -and $p(z)$ -plots were used to interpret the flow in the Cambrian-Devonian hydrostratigraphic group. Formation water density ranges between approximately 1040 and 1140 kg/m³. An average reference

density $\rho_0 = 1090 \text{ kg/m}^3$ was used to calculate hydraulic heads in order to minimize the DFR, and to be able to analyze the flow using hydraulic heads only (see Chapter 2). Maps of salinity and bicarbonate distributions were used in the hydrochemical analysis. The respective ranges of hydraulic head and salinity values for the Cambrian-Devonian aquifers are presented in Table 7.1.

Aquifer	$H_0 (\rho_0 = 1090 \text{ kg/m}^3)$	TDS
Wabamun	480 – 810 m	116 – 265 g/l
Winterburn	450 – 750 m	130 – 265 g/l
Woodbend-Beaverhill L.	600 – 750 m	120 – 262 g/l
Elk Point	605 – 775 m	178 – 300 g/l
'Basal sandstone aquifer'	600 – 650 m	217 – 252 g/l

Tab. 7.1: Summary of ranges in hydraulic head and salinity in the Cambrian-Devonian aquifers. Hydraulic heads were calculated with a reference density of 1090 kg/m^3 .

Similar to the previous chapters, the Cambrian-Devonian hydrostratigraphic group will be presented in descending order, starting with the Wabamun aquifer. Hydrogeological data in the 'Basal Sandstone aquifer' are very sparse (3 values) and therefore, only their range is listed in Table 7.1.

The distribution of pressure data from all Devonian aquifers versus depth (Fig. 7.3a) shows that generally the Devonian aquifers are hydrostatically to sub-hydrostatically pressured, except for a small group of pressure data from the Wabamun and Winterburn aquifers that plot above-hydrostatic. In Figure 7.3b, pressure data plot along a line representative of an average brine gradient of 10.7 kPa/m , which approximately corresponds to the pressure gradient in a static column of brine with a density of 1100 kg/m^3 . This indicates that all Devonian aquifers seem to be in good hydraulic communication or are controlled by similar boundary conditions to flow.

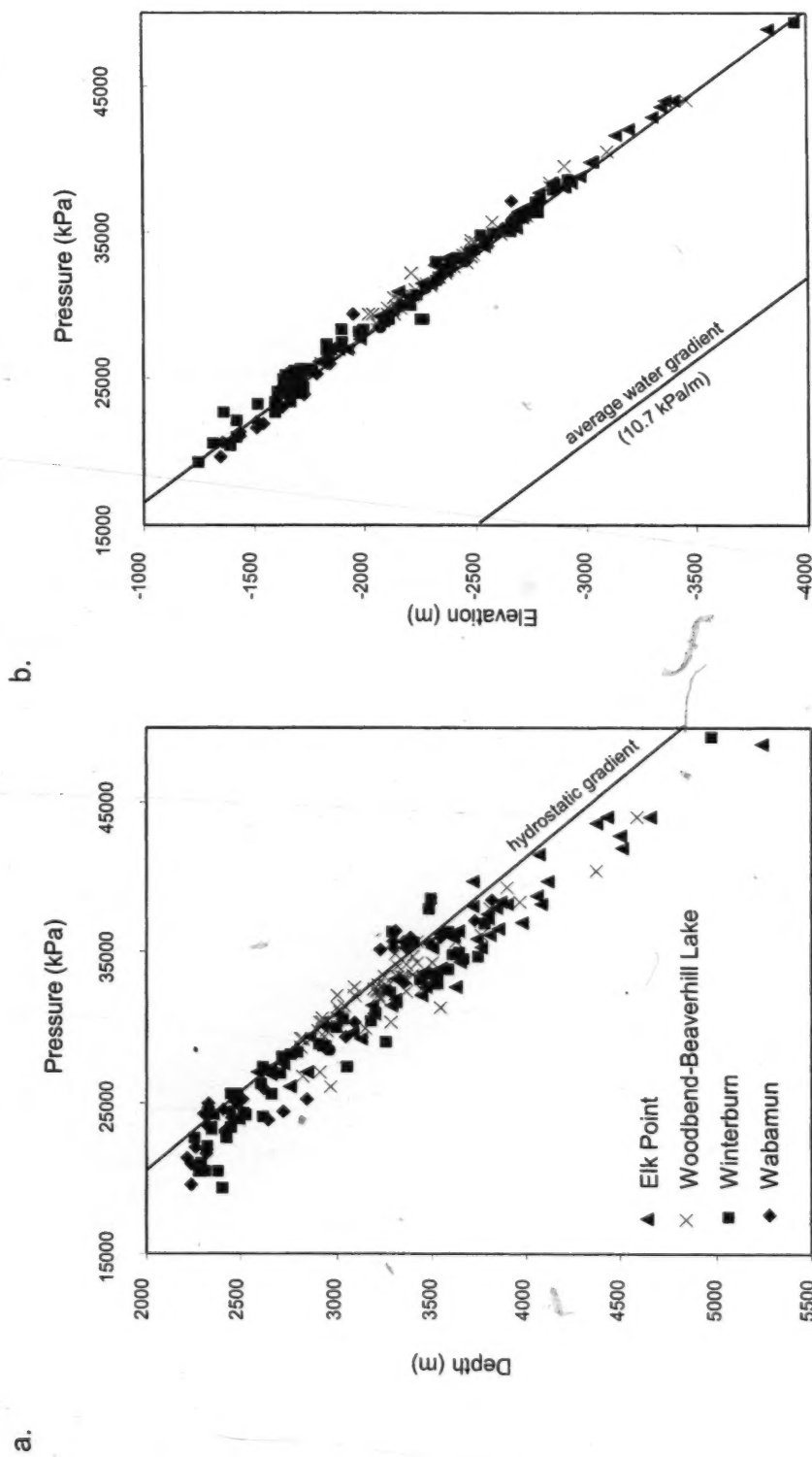


Figure 7.3: Pressure variation with: a) depth, and b) elevation in the Devonian aquifers in the study area.

Wabamun aquifer

Hydraulic heads in the Wabamun aquifer generally decrease north-northeastward from > 800 m to less than 500 m (Fig. 7.4). A steep hydraulic gradient is present in the east-central part of the study area, where hydraulic heads drop by approximately 200 m (800 – 600 m) northward over a 20 km distance. In contrast, in the northern half of the study area hydraulic heads decrease eastward with a relatively constant hydraulic gradient of approximately 10 m/km.

The salinity of formation waters in the Wabamun aquifer generally increases northward in the direction of decreasing hydraulic heads from 115 to 265 g/l (Fig. 7.5). The bicarbonate concentrations show a similar, yet reversed, trend, decreasing from > 2.5 g/l to < 0.5 g/l north and northeastward (Fig. 7.6).

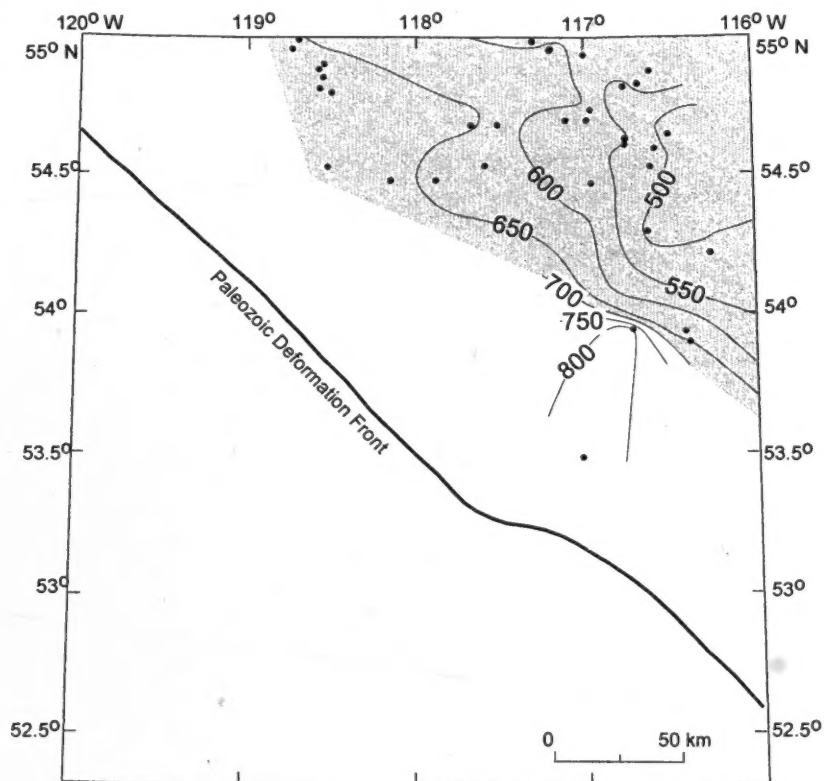


Figure 7.4: Hydraulic head distribution in the Wabamun aquifer (50 m contour interval, H calculated with $\rho_0 = 1090 \text{ kg/m}^3$). For better visualization purposes areas where hydraulic heads < 700 m are shaded in grey.

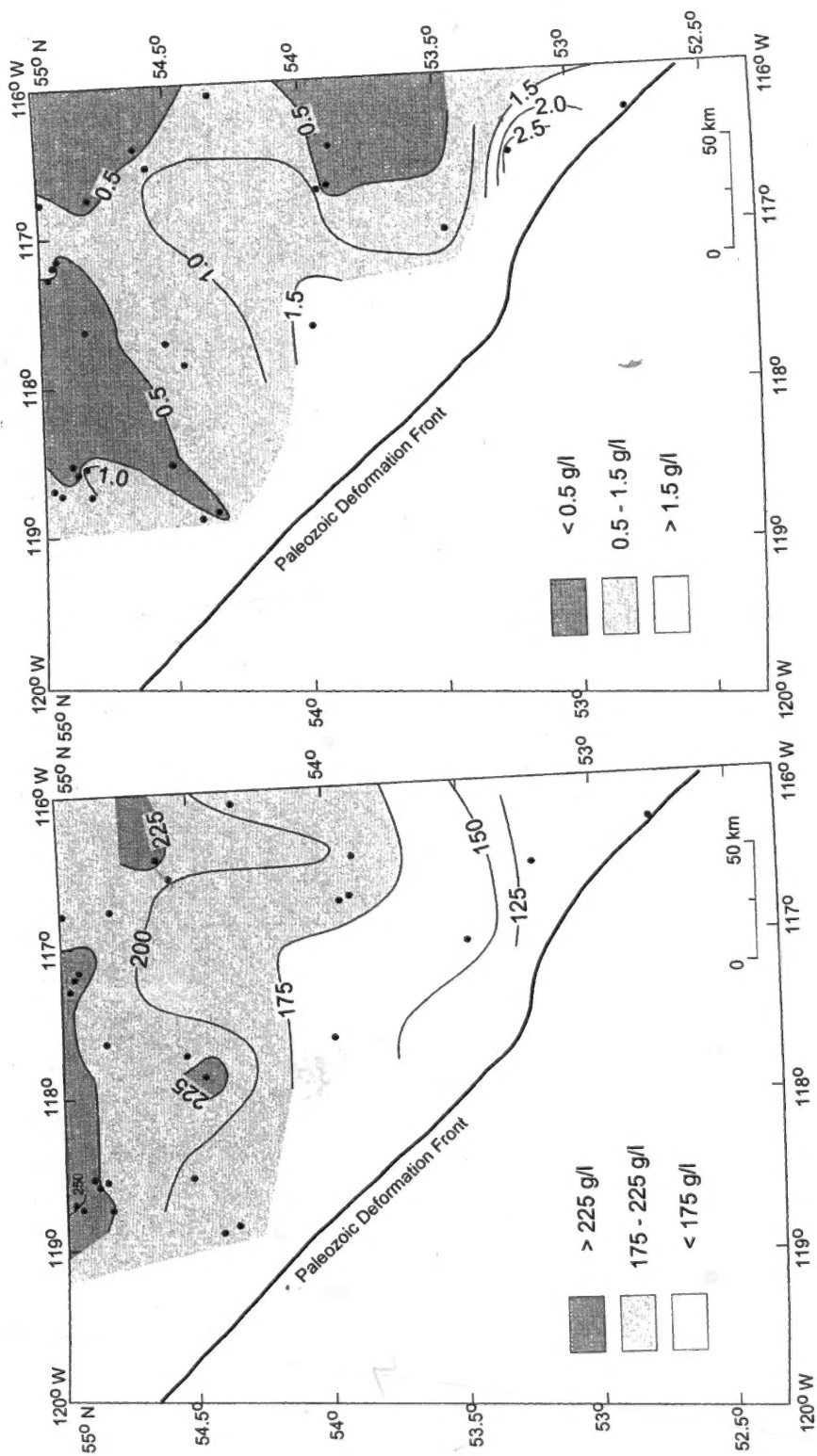


Figure 7.5: Salinity distribution in the Wabamun aquifer (25 g/l contour interval).

Figure 7.6: Bicarbonate distribution in the Wabamun aquifer (0.5 g/l contour interval).

Winterburn aquifer

Hydraulic heads in the Winterburn aquifer generally decrease from > 700 m along the deformation front to less than 550 m in the northeastern corner of the study area (Fig. 7.7). A "tongue" of relatively high hydraulic heads (> 700 m) and steep hydraulic gradient extends from the deeper parts of the aquifer northward, approximately along 117° W. Hydraulic heads decrease in a radiating manner, changing from east- to northwestward, away from the high hydraulic-head "tongue".

The salinity of formation waters in the Winterburn aquifer generally increases north-northwestward, from 130 to 265 g/l, with a relatively steep increase from 175 to 200 g/l (Fig. 7.8) along the limit of the tongue with high hydraulic heads (Fig. 7.7). As in the overlying Wabamun aquifer, the bicarbonate concentrations show a similar, yet reversed, trend, decreasing from > 3.0 g/l to < 0.5 g/l (Fig. 7.9).

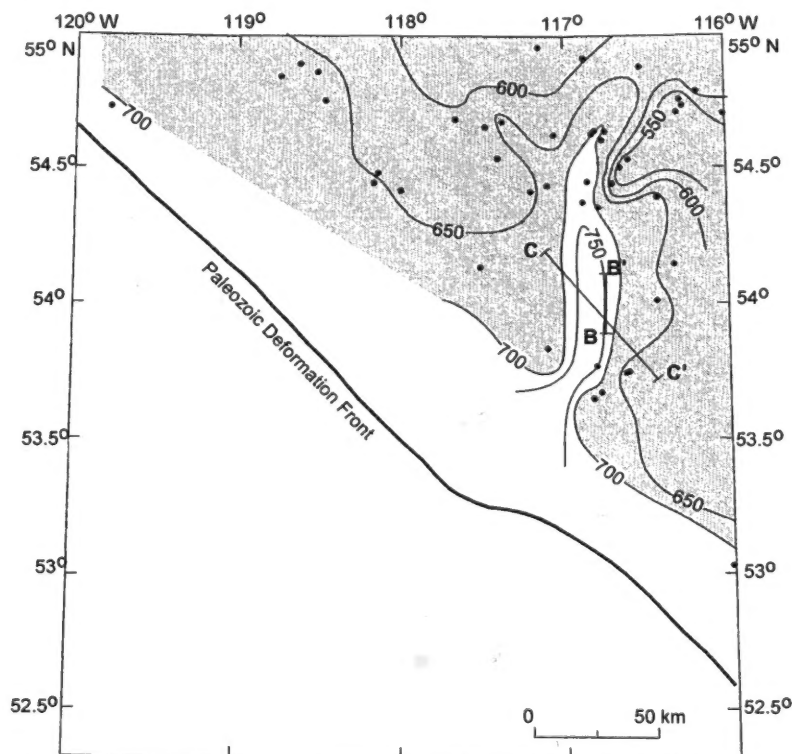


Figure 7.7: Hydraulic head distribution in the Winterburn aquifer (50 m contour interval, H calculated with $\rho_0 = 1090 \text{ kg/m}^3$). Areas where hydraulic heads < 700 m are shaded in grey for better visualization purposes. Lines of cross-sections B-B' and C-C' refer to Figures 7.20 & 7.21, respectively.

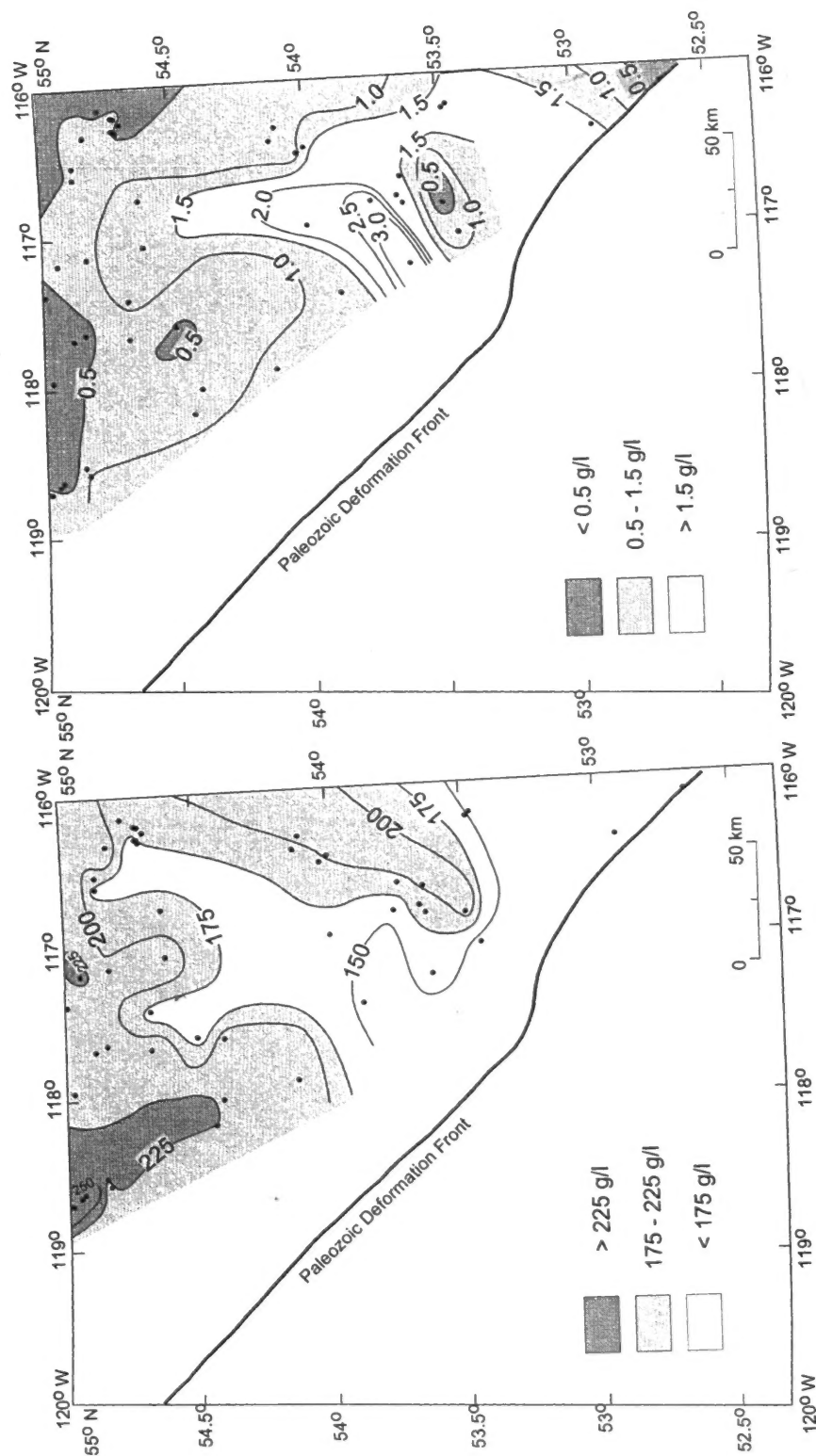


Figure 7.8: Salinity distribution in the Winterburn aquifer (25 g/l contour interval).

Figure 7.9: Bicarbonate distribution in the Winterburn aquifer (0.5 g/l contour interval).

Woodbend-Beaverhill Lake aquifer

Hydraulic heads in the Woodbend-Beaverhill Lake aquifer generally decrease from > 750 m along the deformation front to less than 650 m along the eastern boundary of the study area (Fig. 7.10). "Tongues" of relatively high hydraulic heads (> 700 m) and steep hydraulic gradient extent from the deeper parts of the aquifer northeastward, approximately 150 km away from the deformation front. Excepting the steep hydraulic gradients near the high hydraulic-head tongues, the generally low hydraulic gradients suggest $\pm$ stagnant flow conditions.

The salinity of formation waters in the Woodbend-Beaverhill Lake aquifer generally increases north-northwestward from 120 to 260 g/l with a relatively steep increase from 175 to 250 g/l (Fig. 7.11) approximately along the limit of the tongues with high hydraulic heads (Fig. 7.10). Similar to the overlying aquifers, the bicarbonate concentrations show a similar, yet reversed, trend, decreasing from > 2.5 g/l to < 0.5 g/l (Fig. 7.12).

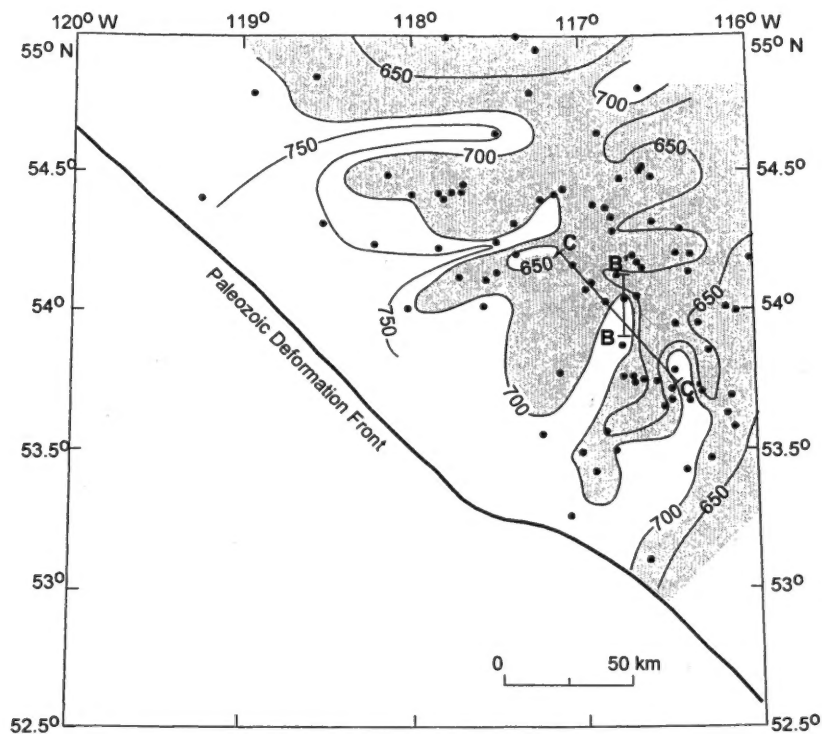


Figure 7.10: Hydraulic head distribution in the Woodbend-Beaverhill Lake aquifer (50 m contour interval; H calculated with $\rho_0 = 1090 \text{ kg/m}^3$). Areas where hydraulic heads $< 700 \text{ m}$ are shaded in grey for better visualization purposes. Lines of cross-section B-B' and C-C' refer to Figures 7.20 & 7.21, respectively.

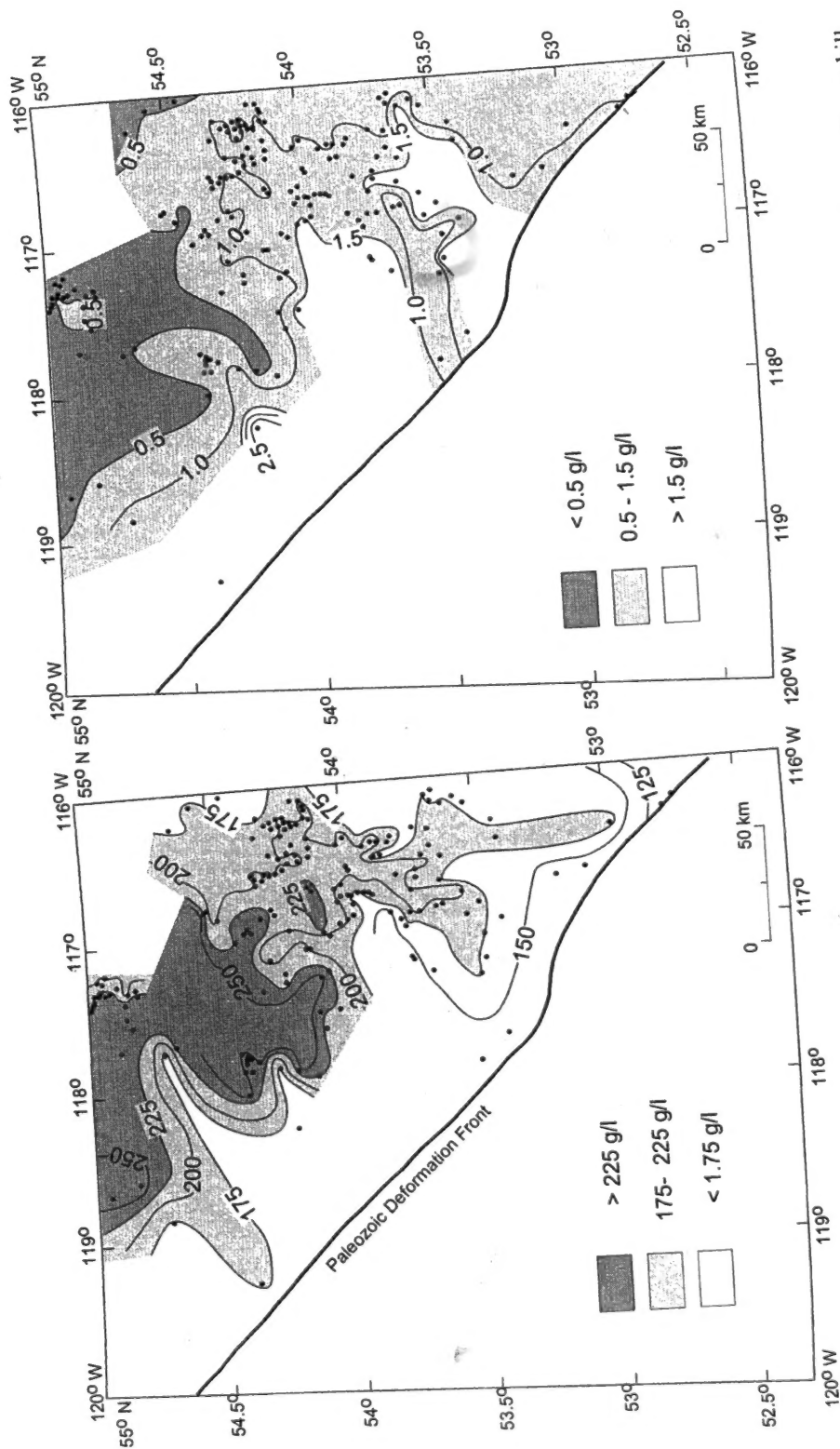


Figure 7.11: Salinity distribution in the Woodbend-Beaverhill Lake aquifer (25 g/l contour interval).

Figure 7.12: Bicarbonate distribution in the Woodbend-Beaverhill Lake aquifer (0.5 g/l contour interval).

Elk Point aquifer

Hydraulic heads in the Elk Point aquifer decrease from > 750 m in the southeast to less than 625 m in the northeastern corner of the study area (Fig. 7.13). Sparse data in the south and lack of data in the central part of the study area restrict the representation of the Elk Point aquifer to the northeastern corner of the study area (s. box in Figure 7.13 referring to Chapter 2). The maximum hydraulic gradient can be observed from approximately 670 m in a S-N trending tongue in the centre of the (sub-) study area to less than 625 m at the eastern boundary. However, using a 25 m contour interval probably is beyond the appropriate resolution that should be used in this deep Devonian aquifer (see Chapter 3; 3.3.4). Rather, relatively uniform hydraulic head values around 650 m indicate $\pm$ stagnant flow conditions in the northern part of the study area, and potential for northward flow from areas of 750 m in the south can be inferred only on a very regional scale.

The salinity of formation waters in the Elk Point aquifer generally increases northward in the direction of decreasing hydraulic heads from 178 to 300 g/l, with a relatively steep increase from 200 to 250 g/l along 54.25° N, in the centre of the study area (Fig. 7.14). The bicarbonate concentrations show a similar, yet reversed, trend, decreasing northward from > 0.75 g/l to < 0.25 g/l (Fig. 7.15). The exception is an area with a few values < 0.25 g/l between 53.5° and 54.0° N, which creates a tongue of relatively high bicarbonate concentration approximately following the 200 g/l salinity contour line (Fig. 7.15).

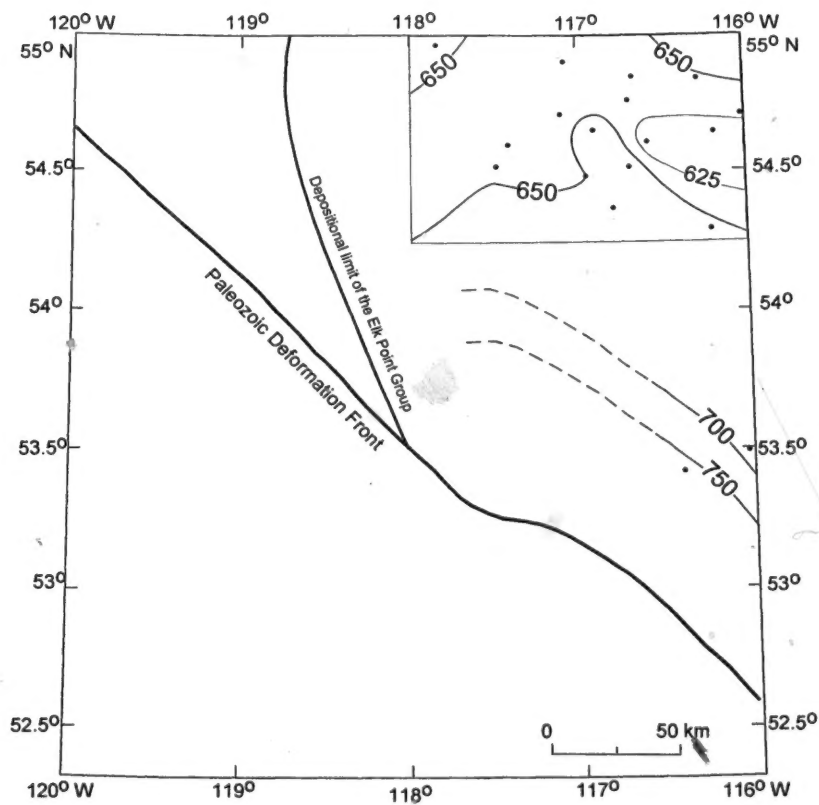


Figure 7.13: Hydraulic head distribution in the Elk Point aquifer (50 m contour interval, except for the addition of the 625 m contour line; H calculated with $\rho_0 = 1090 \text{ kg/m}^3$). The box in the northeastern corner of the map shows the area used in Chapter 2 to examine the effect of different reference densities in the calculation of hydraulic heads on the flow representation.

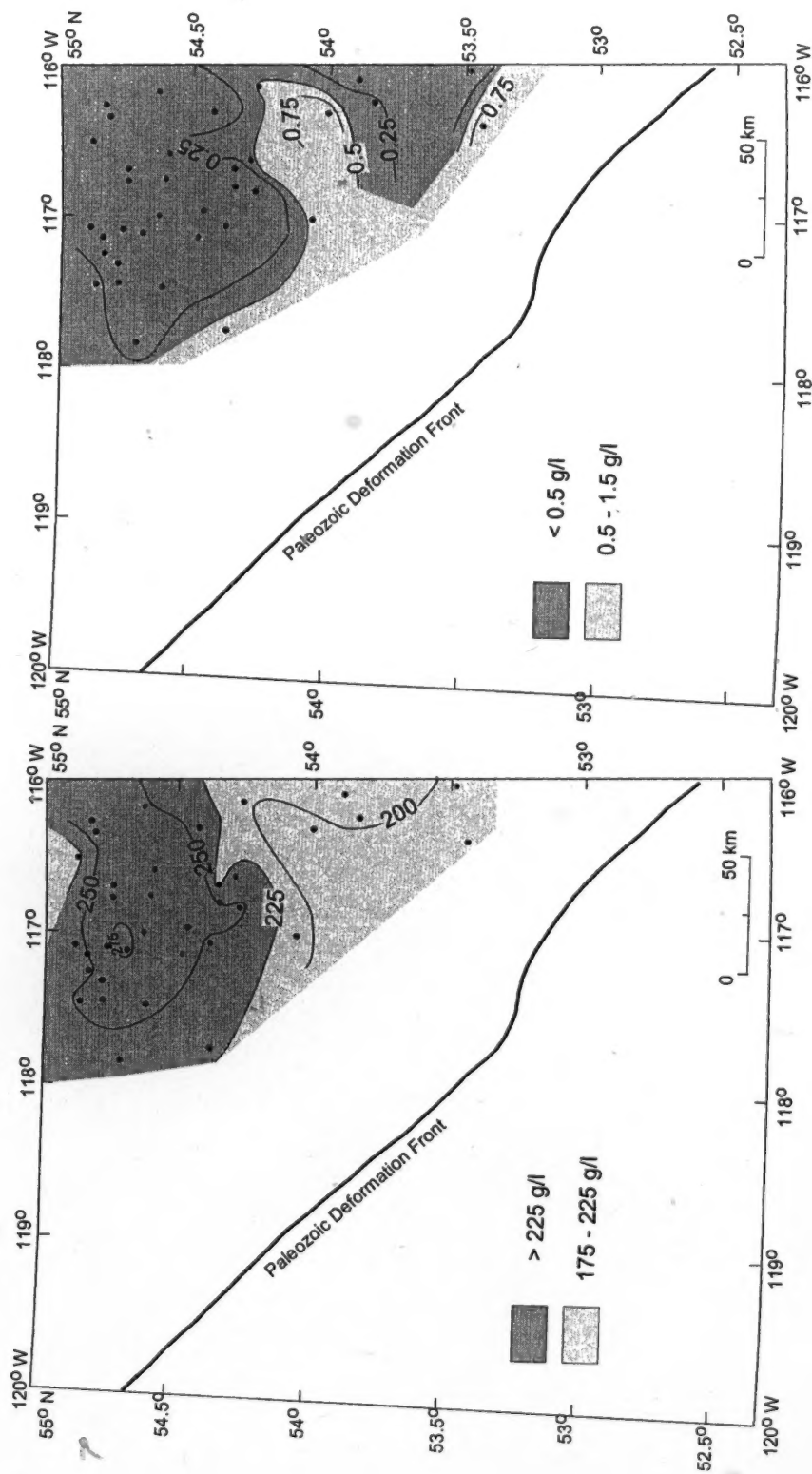


Figure 7.14: Salinity distribution in the Elk Point aquifer (25 g/l contour interval).

Figure 7.15: Bicarbonate distribution in the Elk Point aquifer (0.25 g/l contour interval).

Comparison of selected cations in the Devonian formation waters

The variation of major cation concentrations (Na, Ca, Mg) and Br of Devonian formation waters in the study area is plotted against their chloride content and against the seawater evaporation-dilution curve (SET). The respective plots show that generally these waters are depleted with respect to sodium, magnesium and bromide, and have excess calcium in comparison to water derived only from the evaporation of seawater (Fig. 7.16). For comparison, the variation of major ions versus chloride in the overlying Mississippian aquifer is offset distinctively from the main group of Devonian data.

Summary of hydrogeological observations

- Hydraulic heads generally decrease north-northeastward, updip in all Devonian aquifers;
- Hydraulic head values in the Middle Devonian aquifer system range from 625 to 750 m, which is smaller than the range of H_0 in the Upper Devonian aquifer system (500 – 800 m);
- A concurrent, steep change in hydraulic heads, salinity and bicarbonate concentration can be observed in all Devonian aquifers, around the following approximate values: $H_0 = 700$ m, TDS = 175 g/l, $[\text{HCO}_3^-] = 1.5$ g/l;
- Formation waters are depleted with respect to sodium and magnesium and have excess calcium in comparison to water derived only from the evaporation of seawater;
- The discontinuous change in the hydrogeological data has different patterns in the various Devonian aquifers: a) 'interfingering' in the Woodbend-Beaverhill Lake, b) a single tongue in the Winterburn, and c) relatively linear in the Elk Point and Wabamun.

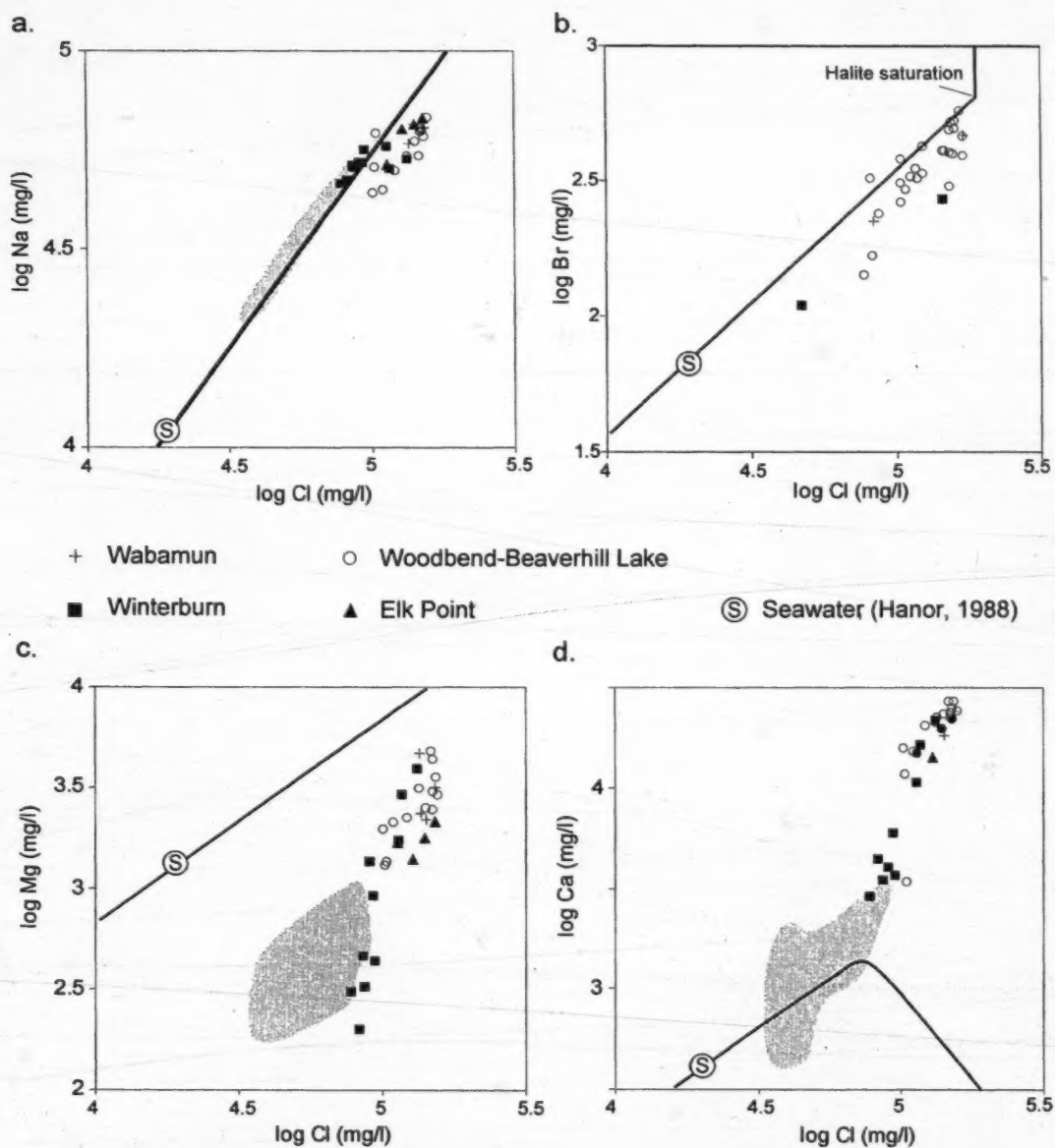


Figure 7.16: Cross plots versus chloride of: a) sodium, b) bromide, c) magnesium, and d) calcium for formation waters in the study area from the Cambrian-Devonian succession. Shaded area represents data distribution in the underlying Mississippian aquifer. The black line on figures a, b, c, and d represents the respective seawater evaporation curves experimentally determined by McCaffrey et al. (1986).

7.4 Interpretation of flow patterns

The general, regional flow patterns are shown in Figure 7.17. The relatively abrupt change in the salinity and bicarbonate concentrations observed in each Devonian aquifer suggests that it is possible to distinguish between a 'light brine' and a 'heavy brine', defined by approximate TDS ranges of < 175 g/l and > 225 g/l, respectively.

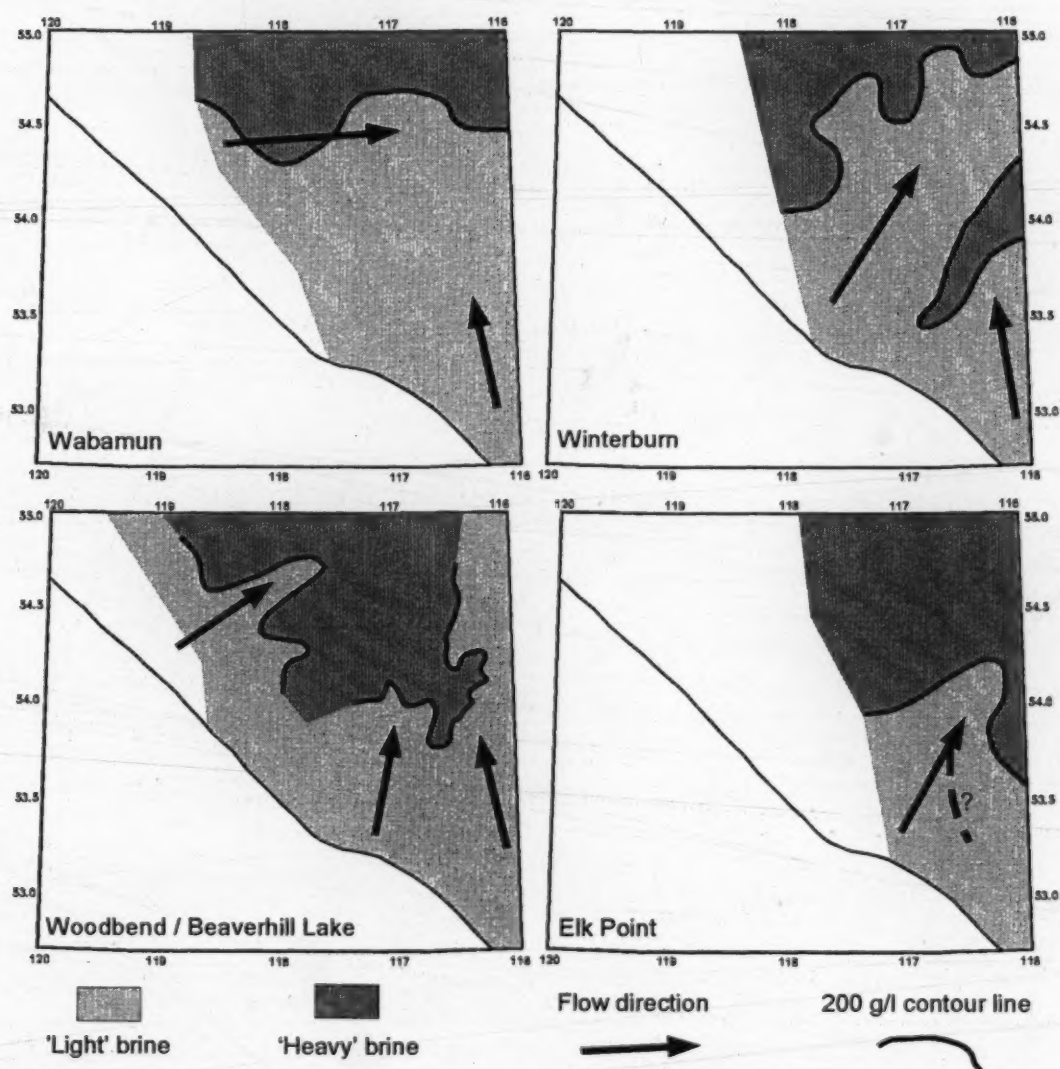


Figure 7.17: Patterns of brine displacement and inferred flow directions in the Devonian aquifers.

No absolute value for the boundary between these two brines can be defined because of variations between the different aquifers and in data accuracy, so that salinities between 175 and 225 g/l will be referred to as 'intermediate' or 'mixing zone' values. Generally, hydraulic gradients are only high along the boundary between the 'light brine' and a 'heavy brine', suggesting a decrease in permeability or transmissivity across that boundary (see Fig. 2.1c in Chapter 2, and Eqs. 2.16 and 2.18). However, in the area that is taken up by the 'heavy brine', small differences in hydraulic head suggest $\pm$ sluggish flow; hence sluggish movement of the 'heavy brine'. Only on a regional scale, the potential for updip, northeastward flow can be inferred from areas of high hydraulic head (> 700 m) along the deformation front. The exception is the northern half of the Wabamun aquifer, where a relatively constant hydraulic gradient of 100 m / 75 km along 54.5° N suggests eastward flow of formation water

Along the deformation front, in the deep parts of the Cambrian-Devonian hydrostratigraphic group, there are no intervening shaly aquitards, and the stacked Devonian carbonate complexes form a contiguous aquifer (Skilliter, 1999). The light brine is present in this part of the study area and hydraulic heads are high, suggesting updip flow towards hydraulic head lows in the northeast and displacement of the heavy brine. Apart from this general feature, the hydrogeological patterns are different in the various Devonian aquifers, which are caused by the thickening of intervening shale aquitards and variations in permeability within each aquifer. These patterns can be characterized by: a) analysis of the competence of intervening aquitards, b) delineation and characterization of preferential flow paths, and c) investigation of fluid origin and flow driving mechanisms.

Preferential flow paths and aquitard competence

The influence of lateral and vertical permeability variations on flow in the Cambrian-Devonian hydrostratigraphic units have been examined in descending order in the stratigraphic succession, starting at the upper confining boundary. The offset of pressure data in the $p(z)$ -plots (Figs. 7.18 a and c) and the difference in hydraulic heads and in the salinity range of formation waters between the Permo-Mississippian and Wabamun aquifers (s. Tab. 6.2, Chapter 6) indicate that the Exshaw-Banff aquitard is a very effective barrier to flow in the study area. Pressures in the Wabamun aquifer plot closer to hydrostatic than those in the overlying Permo-Mississippian aquifer, which implies higher hydraulic heads and a potentially upward gradient to flow from the Wabamun into the Permo-Mississippian aquifer. In the northeast corner of the study area, however, pressures in both aquifers approximately plot along the same gradient (Fig. 7.18 b) and hydraulic heads are in the same range. This indicates that pressures in both aquifers have adjusted to the same boundary conditions. However, the salinity in the Permo-Mississippian aquifer (100 – 150 g/l Fig. 6.10) is still significantly lower than that in the Wabamun aquifer (200 – 225 g/l, Fig. 7.5) so that cross-formational flow through the Exshaw-Banff aquitard in this area seems unlikely, and formation water only moves laterally in both aquifers.

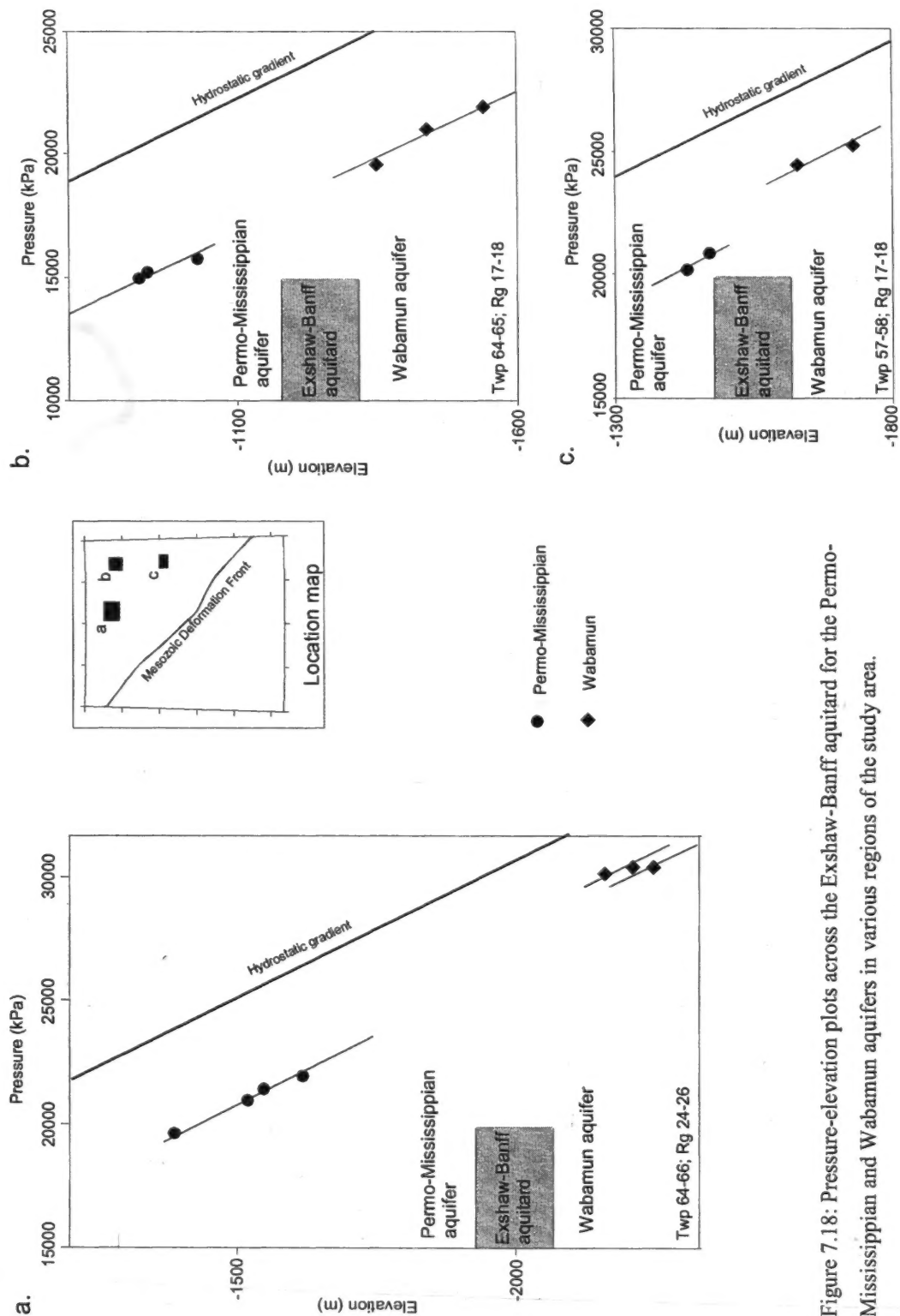


Figure 7.18: Pressure-elevation plots across the Exshaw-Banff aquitard for the Permo-Mississippian and Wabamun aquifers in various regions of the study area.

The hydrogeological patterns in the Wabamun aquifer further suggest that the permeability distribution is more homogeneous than in the Winterburn and Woodbend-Beaverhill Lake aquifers. The limestones in the Wabamun aquifer generally have a fairly low porosity and permeability, but these properties are significantly increased in the dolomitized parts (Saller and Yaremko, 1994). The hydrogeological data resolution in the Wabamun aquifer is relatively poor and the dolomite content is averaged over the entire aquifer thickness. Nevertheless, a general correlation between the degree of dolomitization and salinity distribution appears to be present. The light brine may have displaced the heavy brine from those parts of the aquifer that have a high dolomite content, whereas the less permeable limestone parts obstruct lateral flow (Fig. 7.19).

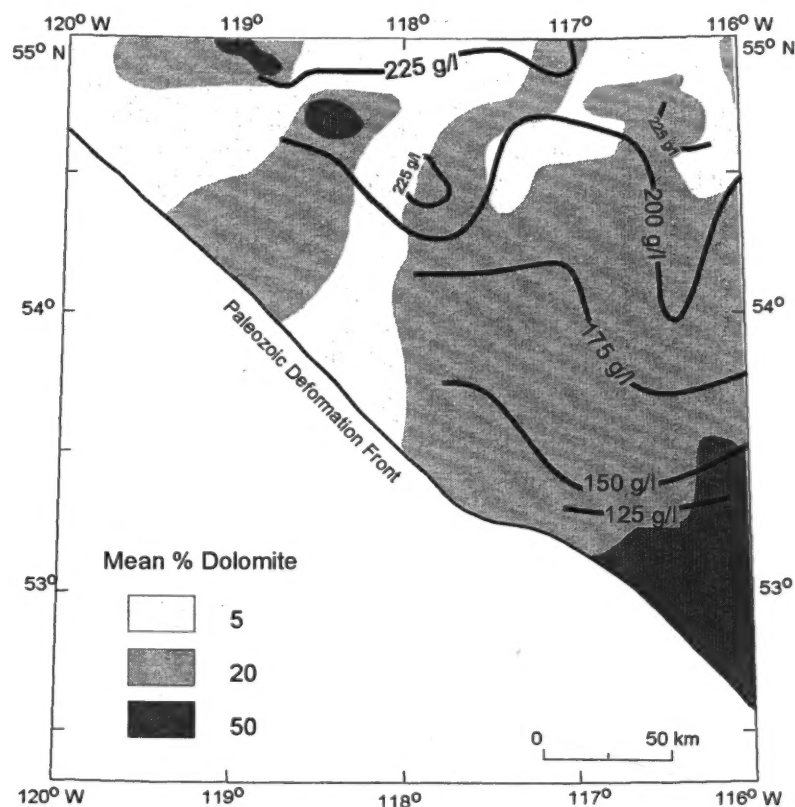


Figure 7.19: Correlation between salinity and average, regional-scale dolomite distribution in the Wabamun aquifer (dolomite-% distribution after Halbertsma, 1994).

Generally, there is good agreement between hydraulic head and salinity distributions in the Wabamun and Winterburn aquifers, which suggest that the intervening Graminia siltstone is a relatively inefficient aquitard. The only noteworthy difference between these two aquifers can be observed in the area of the high hydraulic head tongue in the Winterburn aquifer, along longitude 117° W (Fig. 7.7). Hydraulic heads near the deformation front in the Wabamun aquifer start out at higher values (> 800 m) than in the Winterburn aquifer (~ 750 m), which implies a horizontal barrier to flow. At approximately 53.75° W hydraulic heads in both aquifers are at ~ 750 m, but hydraulic heads in the Wabamun aquifer drop rapidly northward to ~ 650 m, while they stay constant in the Winterburn aquifer. According to the hydrostratigraphy, there are no shale aquitards along the deformation front that could impede the vertical hydraulic communication between the Winterburn and Wabamun aquifers, which could explain the difference in hydraulic heads. One possible explanation would be a generally low-permeability layer in this part of the Wabamun Group due to a low degree of dolomitization. Another possibility is that the two pressure data resulting in $H_0 > 800$ m were measured in relatively isolated, fractured reservoirs (Chevron Canada Resources staff, pers. Comm.). More data than currently available, and further study are needed to address this issue of hydraulic continuity (or absence thereof) between and within the Winterburn and Wabamun aquifers in this region. Although the Upper Devonian succession is inferred to be a contiguous aquifer system on a regional- and basin-scale, areas that are not significantly dolomitized in the Wabamun Group and basinal facies in the Winterburn Group appear to be of low permeability, and locally may act as aquitards.

The Ireton shales form the main aquitard in the Cambrian-Devonian hydrostratigraphic group. Hydraulic heads decrease in the Wabamun and Winterburn aquifers to approximately 500 m, whereas hydraulic head values in the Elk Point and Woodbend-Beaverhill Lake aquifers decrease only to approximately 625 m from the southwest to the northeast. In addition, the light brine advanced farther updip in the Upper Devonian aquifer system than in the Middle Devonian aquifer system (Fig. 7.17). This shows that the Ireton shales separate the Woodbend from the overlying Winterburn aquifer and form an effective aquitard in the northeast between the Middle and Upper Devonian aquifer

systems. Selected stratigraphic cross sections show that the Ireton aquitard thins considerably above Leduc reefs, and that the latter may be even in direct contact with overlying Nisku reefs (Figs. 7.20 and 7.21), where the Ireton is thin or absent. These 'windows' in the Ireton aquitard probably are areas where cross-formational flow between Woodbend-Beaverhill Lake and Winterburn aquifers occurs, which has been identified previously in the same strata in carbonate complexes southeast of the study area (Rostron and Tóth, 1997; Rostron et al., 1997; Anfort et al., 2001).

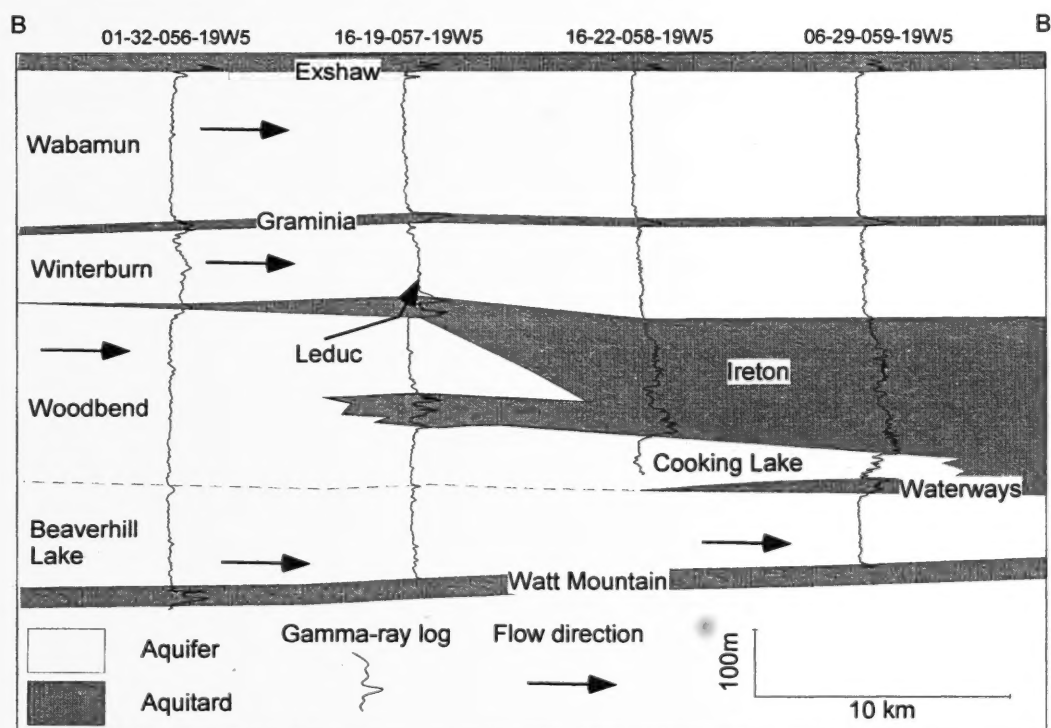


Figure 7.20: (Hydro-)Stratigraphic cross-section perpendicular to the deformation front showing a single Devonian aquifer at the left hand side of the cross-section (S), which is successively subdivided into two aquifer systems, and cross formational flow across the Ireton aquitard. See Figures 7.7, 7.10 & 7.22 for line of cross section.

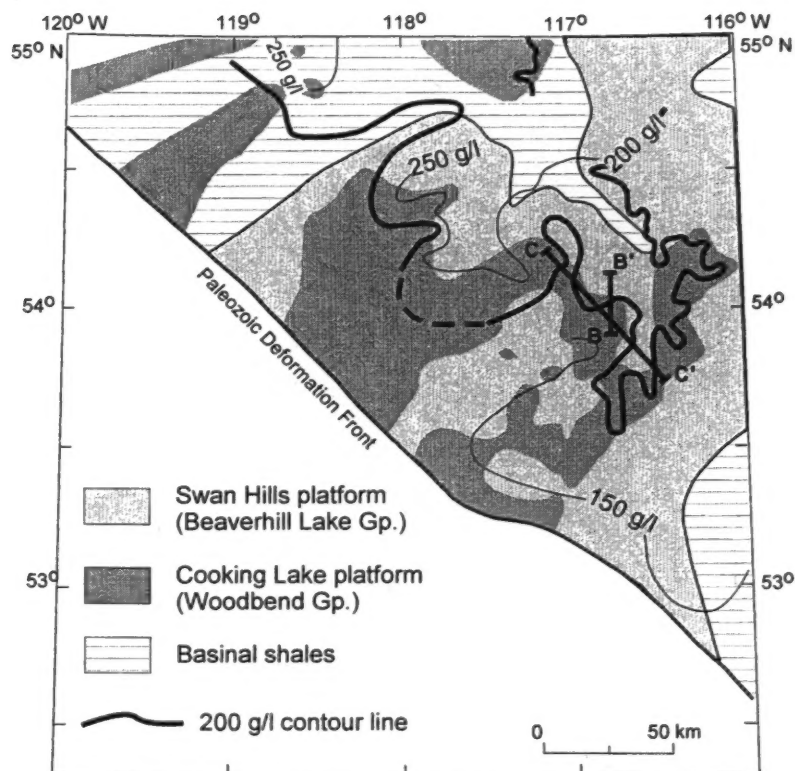


Figure 7.22: Correlation between salinity and facies distribution in the Woodbend-Beaverhill Lake aquifer.

The hydrostratigraphic cross section (Fig. 7.21) shows how the Woodbend-Beaverhill Lake aquifer thins abruptly in this area, permitting formation water flow to be forced upwards, through the 'windows' in the Ireton shales, into the Winterburn aquifer. Along the same line of cross section, the large tongue of light brine in the Winterburn aquifer extends farther to the north (Fig. 7.7) and represents a sub-lateral "continuation" of the 'finger' of light brine, in the Woodbend-Beaverhill Lake aquifer. The 'interfingering' pattern in the Woodbend-Beaverhill Lake aquifer is probably caused by the higher permeability in the Leduc reef carbonates. The high hydraulic head 'fingers' (Fig. 7.10) coincide with the locations of the Leduc reef build-ups (Fig. 7.20), which suggest that formation water flow is channeled through these reefs. Apparently, flow in the Woodbend-Beaverhill Lake aquifer is governed by a combination of the lateral changes of permeability and transmissivity, controlled by depositional facies distribution and

aquifer thickness, and by hydraulic communication with the Winterburn aquifer at selected locations where the intervening Ireton aquitard is thin or absent.

The hydraulic head distribution in the Elk Point aquifer (Fig. 7.13) suggests relatively stagnant flow conditions in the northeastern corner of the study area, which is filled with the heavy brine. There appears to be a tongue of fresher formation water coming from the south (Fig. 7.14), which is deflected towards the eastern boundary of the study area. The intervening Watt Mountain aquitard is very thin to non-existent in this area, and the heavy brine (> 250 g/l) may continue in the overlying Woodbend-Beaverhill Lake aquifer (this interpretation is tentative and cannot be confirmed due to the lack of data).

Insufficient hydrogeological data exist for the 'Basal sandstone aquifer' in the study area and, therefore, it is difficult to assess the competence of the Middle Cambrian aquitard. The crystalline Precambrian basement is commonly assumed to act as an aquiclude (Hitchon et al., 1990; Bachu, 1995a, 1999), and there is no evidence for the presence of formation waters in the basement in the study area. The nearest occurrence of waters in the crystalline basement are Ca-Cl brines that have been reported from the Precambrian Shield > 500 km to the northeast (Fritz and Frape, 1987). On the other hand, studies on Sr – isotopes from carbonate cements in Devonian reefs suggest that basement fluids may have migrated upwards via faults, which influenced the diagenetic history in the deep parts of the study area (Machel and Cavell, 1999; Mountjoy et al., 1999). Therefore, conduits for fluid flow in the crystalline basement might still exist, but they are most probably restricted to faults and shear zones (Bachu, 1999).

Fluid origin and flow driving mechanisms

The Cambrian to Devonian sediments were deposited in a marine environment, which infers that formation waters started out as seawater. The major salt deposits in the Devonian Elk Point Group north of the study area (Meijer Drees, 1994) suggest that parts of the original seawater in the Middle Devonian succession have evaporated beyond the

point of halite saturation. Other, less evolved evaporitic sediments occur in the Winterburn and Wabamun Groups in the southern part of the Alberta Basin (Switzer et al., 1994; Halbertsma, 1994), but no significant amounts of evaporites were deposited in the study area itself. Connolly et al. (1990a) plotted log Cl versus log Br for formation waters in central Alberta, and all their data fall on or above the seawater evaporation trajectory (Carpenter, 1978), so they concluded that the waters are derived from seawater evaporation or from evaporation and subsequent dilution by freshwater, respectively. However, the bromide concentrations in Figure 7.16b plot on or below the SET, which suggests that the main volume of brines did not reach the point of halite saturation, and halite dissolution played a major role in concentrating the brines in the study area, as was suggested by Hitchon et al. (1971).

The depletion in magnesium with respect to the SET (Fig. 7.16c) probably is caused mainly by the dolomitization of limestone (Land, 1987; Spencer, 1987), according to the reaction:



The majority of the dolomite in the Devonian carbonates in the deep parts of the Alberta Basin consists of 'burial dolomites', which formed from diagenetically altered Devonian seawater (Machel et al., 1994; Mountjoy et al., 1999). The process of (replacement) dolomitization causes a concurrent increase in Ca with decreasing Mg in the fluid. However, Mg and Ca show a positive correlation (Fig. 7.23a), indicating that an additional process to dolomitization produced the high Ca content currently observed in the Devonian formation waters. The generally low sulfate concentrations (compared to seawater) and the poor correlation between sulfate and calcium in Devonian formation waters (Fig. 7.23b) shows that the dissolution of gypsum, according to the reaction:



could not have had an important influence on the calcium content either. Also, sulphate concentrations in the Devonian formation waters are in the same range as in the significantly less saline Mississippian waters.

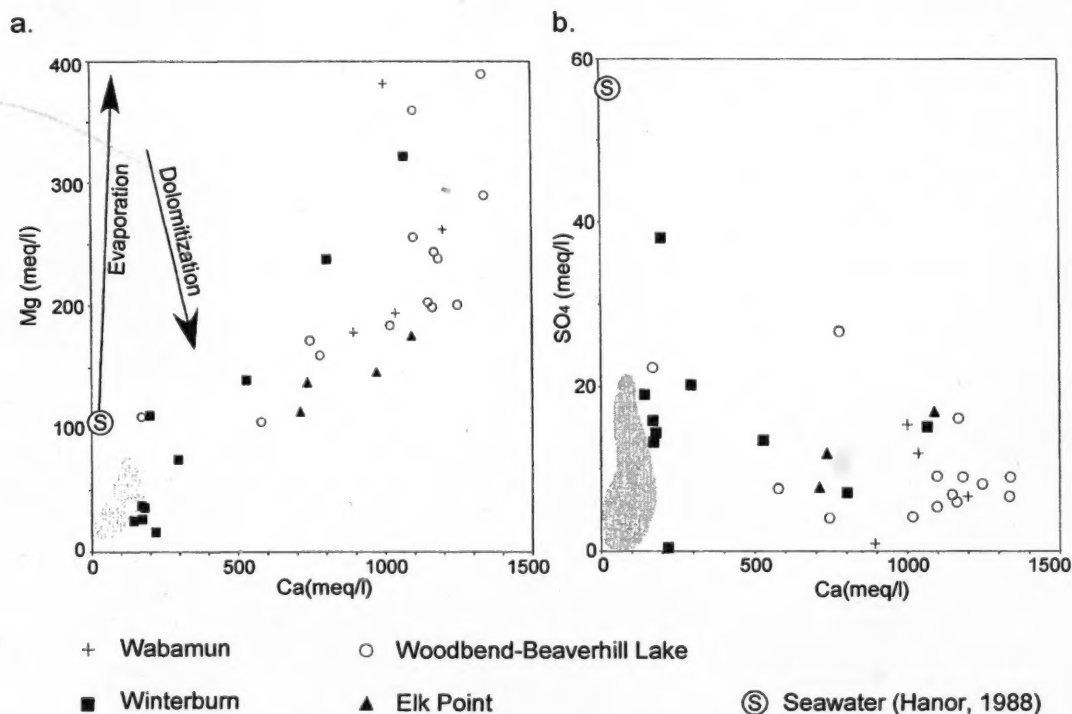
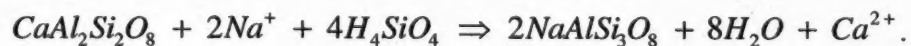


Figure 7.23: Cross plots of calcium versus: a) magnesium, and b) sulfate, for formation waters in the study area from the Cambrian-Devonian succession and the overlying Mississippian aquifer (shaded) for comparison.

The linear correlation between sodium and calcium concentrations with the Basin Fluid Line (BFL) defined by Davisson and Criss (1996) suggests that sodium is replaced by calcium in the formation waters (Fig. 7.24). The mechanisms responsible for this cation exchange is probably the albitization of plagioclase, according to the reaction (Land and Milliken, 1981):



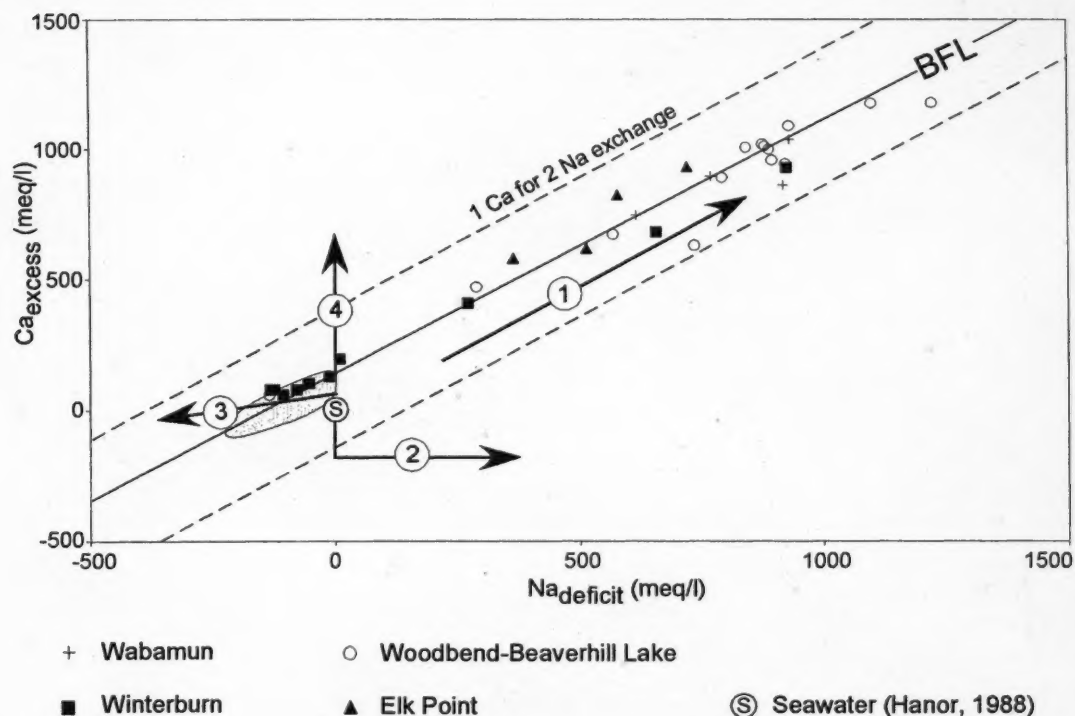


Figure 7.24: Plot of Ca_{excess} - $Na_{deficit}$ for Cambrian-Devonian formation waters in the study area, showing trends for various processes that may have effected the fluid composition. The circled numbers in the figure refer to the trends of: 1) albitization of plagioclase, 2) evaporation of seawater, 3) halite dissolution, and 4) dolomitization and gypsum dissolution. The Basinal Fluid Line (BFL) from Davisson and Criss (1996) is shown for reference. The grey shading shows the distribution of overlying Mississippian data for comparison. (See Chapter 2 for definitions of Ca_{excess} and $Na_{deficit}$ values.)

Apparently, the albitization of feldspar left a predominant chemical signature observed in the present-day Devonian brines, although the processes of evaporation and dolomitization must have affected the early stages of brine evolution as indicated in the rock record. Also, the dissolution of halite must have played a role in concentrating the brines, causing a positive intercept of the BFL on the Ca_{excess} axis (positive Ca_{excess} value for $Na_{deficit} = 0$ in Fig. 7.24) and the shift towards Na/Cl-ratios > 0.85 in relatively low-saline Winterburn formation waters (Fig. 7.25). Alternatively, these high Na/Cl-ratios of

the light brine could be due to mixing with Mississippian formation waters derived from a lateral, regional-scale flow system originating in the south of the study area.

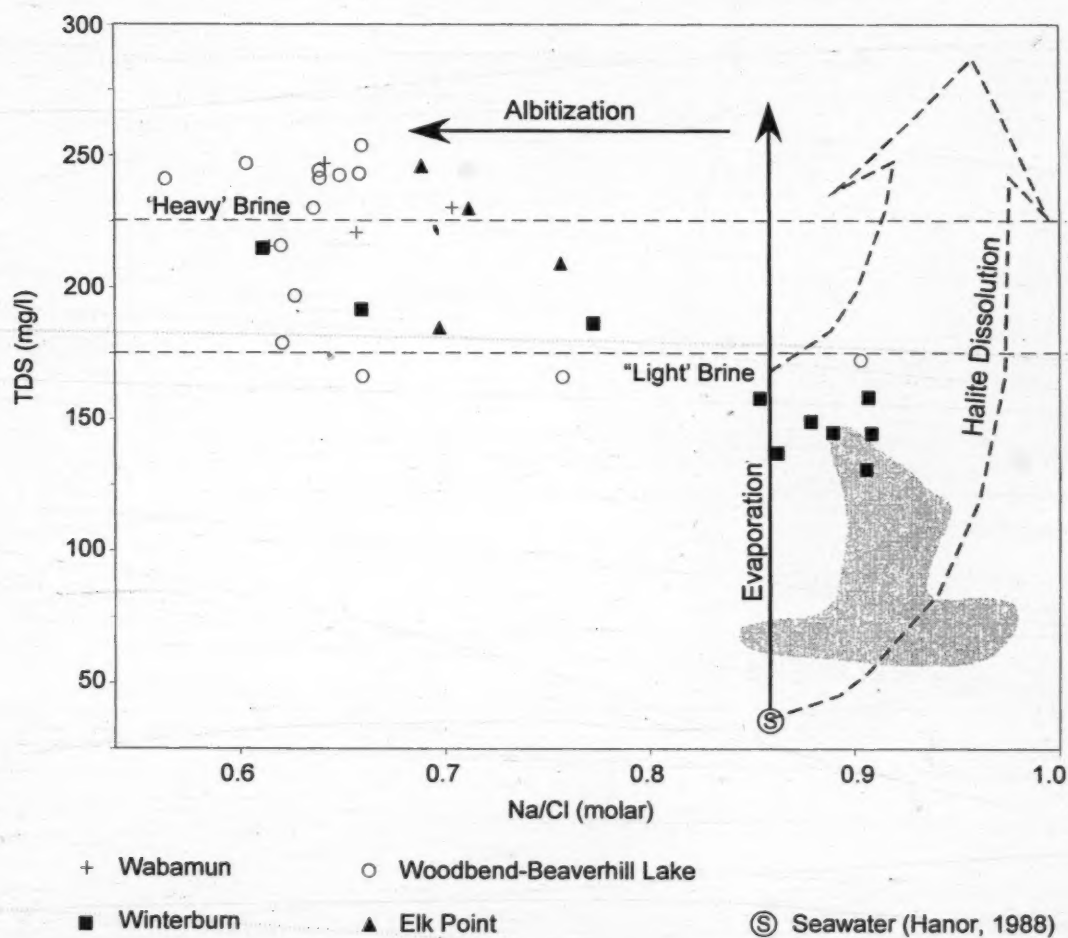


Figure 7.25: Distribution of Na/Cl-ratios versus salinity in Cambrian-Devonian formation waters showing processes that may have produced the brines. The shaded area (grey) shows the distribution of Mississippian data (see Chapter 6) for comparison.

Following Spencer (1987), the following interpretation for the evolution of the Devonian brines is supported by the presented chemical data: a) starting with an original seawater source, b) concentration due to evaporation, c) syn-depositional loss of residual brines, d) downward migration of dense residual brines and heating, e) water-rock interaction (albitization) with sialic crystalline basement rocks and/or Cambrian clastics, f) upward migration of hot brines along faults, g) formation of carbonate cements, and h) mixing with freshwater. According to this interpretation, the heavy brine supposedly represents formation water that entered the Devonian aquifers at the time of dolomitization (Upper Devonian time), whereas the light brine was formed subsequently by mixing of the residual brine with freshwater of unspecified origin (Spencer, 1987). Similarly, a more recent study of the dolomitized Swan Hills platform carbonates suggested that the brine was derived during the precipitation of Graminia Formation evaporites, which subsequently dolomitized the underlying Beaverhill Lake to Winterburn platform carbonates by a combination of seepage reflux and thermal convection (Wendte et al., 1998). This mechanism would explain how the connate brines could have flowed through Cambrian and maybe even Precambrian rocks, which are the most likely sources for feldspars needed in the albitization process.

The main issue that remains to be addressed is the origin of the freshwater component in the process presented above. According to a study of oxygen and hydrogen isotopes in central Alberta, the observed freshwater component in Devonian-Jurassic formation waters has a post-Laramide, but pre-present day age (Connolly et al., 1990b). Connolly et al. (1990b) suggested that, following Hitchon (1969a,b; 1984) and Garven (1989), post-Laramide meteoric recharge of the Devonian aquifers occurred through a gravity-driven flow system, with recharge in the mountain ranges and penetration of meteoric water down to the Precambrian basement. However, considering the large amount of residual brine in the deep basin, this flow system could not have been an effective basin-scale flow system with long-distance lateral flow in the Devonian aquifers, and discharging at the exposed Precambrian Shield, as previously suggested (Hitchon 1969a,b; 1984; Garven, 1989). According to numerical simulations, such a flow system would have

flushed the Alberta Basin of brine within 2 million years (Adams et al., 2000). It appears that the boundary between the light and heavy brines (Fig. 7.17) represents the limit of meteoric freshwater influence (penetration).

The low-salinity waters in the Upper Devonian aquifer system are mainly from the southeastern part of the study area and plot along the respective Mississippian chemistry trends (Figs. 7.16, 7.25). This suggests as a first possibility that the 'light' Devonian brine could be a mixing product of the residual Devonian heavy brine and Mississippian formation waters. However, the intervening Exshaw-Banff aquitard obstructs direct (vertical) mixing between the Devonian and Mississippian aquifers. Therefore, it appears more likely that formation water mixing with meteoric water occurred laterally, along a long-range flow path originating in areas of outcrops at topographic highs in Montana to the south of the study area (Bachu, 1995a; Bachu and Underschultz, 1995; Anfort et al. 2001). Any meteoric recharge had/has to pass either through the Mississippian strata before it reaches the Devonian aquifers, or it has a long flow path from areas of Devonian outcrop in Montana, approximately 500 km south of the study area. In both cases, mixing with residual brine and/or water-rock interaction along the flow path overprinted the meteoric signature.

The relatively low salinity values, in conjunction with low $[Na]/[Cl]$ -ratios < 0.8 (Fig. 7.25), which are predominantly present along the deformation front, suggest the second possibility of a different origin of fresher water in this area, namely from the thrust and fold belt of the Rocky Mountains. However, a hydrogeological study of formation water flow between the deformed and undeformed parts of the Devonian succession in southern Alberta suggests that the present flow systems in the individual thrust sheet are disconnected from each other and from the undeformed part of the Alberta Basin (Wilkinson, 1995). On the other hand, freshwater is believed to have infiltrated down to Mississippian aquifers via convoluted pathways in the over-thrust fault systems (Underschultz and Bartlett, 1999), but maps with the exact locations of such freshwater penetrations have not been published yet. Meteoric recharge through faults could also be

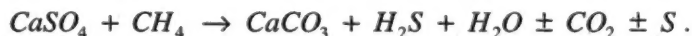
an explanation for the origin of the light brine in the Devonian aquifers in places along the deformation front in the study area, but insufficient hydrogeological data exist in the thrust and fold belt to verify or disprove this hypothesis.

A third possibility for the origin of the lighter brine is the expulsion of formation water by tectonic compression of sediments during the Laramide orogeny. This flow-driving mechanism was introduced by Oliver (1986), although he expected the expelled fluids to have higher salinity and, after a lateral migration over hundreds of kilometres, to be able to form mineral deposits deep within the continent. Machel and Cavell (1999), using strontium isotopes, suggested that late stage calcite cements in the Woodbend reef complexes in the study area have been precipitated from tectonically expelled fluids, but they have shown that the strontium signal could be detected only within a limit of approximately 100 km from the deformation front. The relatively low salinity of the expelled fluids could also be explained by the involvement of metamorphic water from the Precambrian basement. There is no evidence for the presence of formation waters in the crystalline basement in the study area. The nearest occurrence of waters in the crystalline basement are Ca-Cl brines that have been reported from the Precambrian Shield, > 500 km to the northeast (Fritz and Frape, 1982). On the other hand, studies on Sr – isotopes from carbonate cements in Devonian reefs suggest that basement fluids have migrated upwards via faults, which influenced the diagenetic history in the deep parts of the study area (Machel and Cavell, 1999; Mountjoy et al., 1999). Therefore, conduits for fluid flow in the crystalline basement might exist, but they are most probably restricted to faults and shear zones (Bachu, 1999), not identified in the study area. Diagenetic water from the dehydration of clays appears rather improbable, because the most prevalent clay transformation, smectite to illite, takes place at much shallower depths, early in the burial history, and the volume of fluids released is small (Osborne and Swarbrick, 1997).

While the possible origin of relatively fresher water from metamorphic reactions remains to be further investigated, it seems unlikely that the present-day flow pattern is the remnant of tectonic expulsion. According to numerical modeling studies, the excess

pressures generated by tectonic loading would have occurred in pulses and have dissipated after only a few million years (Ge and Garven, 1989, 1994).

A fourth mechanism capable of diluting high-salinity brines is the thermogenic reduction of sulfur (TSR), which can produce freshwater during the thermal generation of hydrocarbon gases according to the reaction (Worden et al., 1996):



This process is believed to cause the dilution of formation waters by up to 50% locally and up to 30% on a reservoir scale (Worden et al., 1996, 1998; Yang et al., 2001). On the other hand, there might be other reactions involved in TSR, some of them consuming water, and the amount of water produced is probably highly variable and, at least in some cases, negligible and may not affect the regional salinity distribution of formation waters (Machel, 1998).

As a fifth possibility, the updip position of the heavy brine could be the result of the long-range, down-dip migration of heavy evaporitic brines from the Williston Basin more than 500 km to the southeast (Chipley and Kyser, 1991), or, more likely, from the area of up to 600 m thick, laterally extensive Middle Devonian evaporite deposits (Meijer Dress, 1994; Grobe, 1999), 100 - 200 km to the east-northeast of the study area.

7.5 Summary and conclusions

The distribution of formation water salinity and hydraulic heads indicates that the Devonian succession in the study area is presently isolated from flow systems in the overlying hydrostratigraphic groups, separated by the competent Exshaw-Banff aquitard. Also, the Devonian aquifers cannot be recharged directly from above because of the hydraulic barriers comprised of thick, competent shales (aquitards), and extensive zones of underpressuring (sinks) and overpressuring (pressure barriers) present in the overlying Cretaceous succession (Chapter 5).

Hydraulic head distributions and hydrochemical data from this study, in conjunction with previous work on the origin of Devonian formation waters (Spencer, 1987; Connolly et al., 1990a,b) suggest that two brines exist in the Cambrian-Devonian succession (Fig. 7.26). A 'heavy' connate brine (> 200 g/l) was probably generated from evaporated Devonian seawater, halite dissolution and subsequent alteration due to water-rock interaction (e.g., albitization, dolomitization). A 'light' brine (< 200 g/l) is found mainly downdip of the heavy brine and the hydrogeological patterns suggest five possible, not necessarily exclusive, origins. In the first case, the less saline formation water may represent a mixture of meteoric water and/or less saline formation water, originating in the thrust and fault belt, with the original connate ('heavy') brine. Secondly, these waters might contain a metamorphic component because tectonically expelled fluids were probably involved in the mixing process. In the third case, the light brine, flowing updip from the south, may have originated as Mississippian seawater that was mixed with Laramide – Pliocene (or present-day?) meteoric water, and is part of a long-range, gravity-driven flow system originating in Montana (Bachu, 1995a). Thermogenic reduction of sulfur may produce variable amounts of fresh water and therefore, represents a fourth mechanism capable of locally diluting saline brines. Alternatively, as a fifth possibility, the light brine could represent the original connate water, that has been displaced by the downdip migration of heavy brines that originate from partial dissolution of thick Middle Devonian evaporite deposits to the northeast of the study area.

The flow of both brines appears to be sluggish, probably as a result of buoyancy and convergence of the two brines. Although tectonic compression has caused the expulsion of fluids from the sediments in the thrust and fold belt and the crystalline basement, and has driven them laterally up to 100 km into the undeformed part of the basin (Machel and Cavell, 1999; Buschkuehle and Machel, 2001), excess pressures from this process probably have dissipated by now. The light brine advances further updip in the Upper Devonian aquifer system than in the Middle Devonian aquifer system (Fig. 7.26). This shows that the Ireton shales form an effective aquitard between the Middle and Upper

Devonian aquifer systems. Cross-formational flow between the two Devonian aquifer systems occurs only in places where the Ireton shales thin out or are absent over Leduc reefs. The lighter brine attempts to flow updip, along large-scale "fingers" that are due to channeled flow along high-permeability pathways (Fig. 7.26). These conduits are probably caused by lithology changes, which are controlled by the depositional facies distribution and dolomitization. The density contrast between the light and heavy brines creates buoyancy forces that oppose the flushing of the high-salinity connate brine, so that the flow direction changes from mainly along dip to along strike in the mixing area of the two brines. This suggests that the lighter brine is attempting to displace laterally the heavier brine, which forms a slug of almost stagnant water, similarly to the basin-scale flow pattern in Devonian aquifers in the Williston Basin (Bachu and Hitchon, 1996).

The results of the current hydrogeological study bear two major implications for further studies, particularly numerical modeling, of flow of Devonian brines in the Alberta Basin. First, numerical models of flow in the Alberta Basin need to consider coupled transport and flow processes to account for the high density of the Devonian brines and the general variations in formation water density. Secondly, two-dimensional, cross-sectional numerical modeling of flow, in many cases, inadequately represents the observed flow of formation waters along preferential flow paths due to the heterogeneous permeability distribution in the Devonian aquifers and to the complexity of the flow pattern.

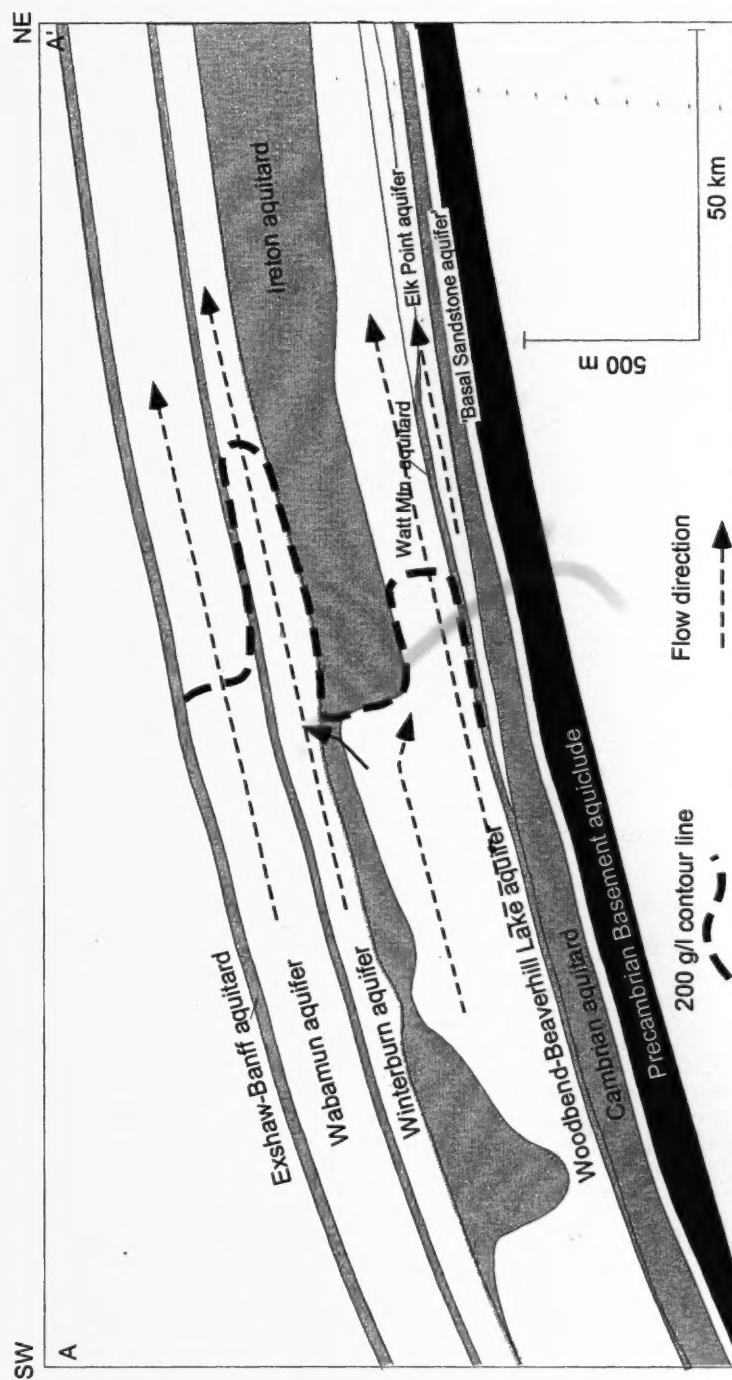


Figure 7.26: Hydrogeological cross section perpendicular to the deformation front showing conceptually the differential advancement of the less saline formation water displacement front against a high-saline connate brine in the Cambrian-Devonian hydrostratigraphic group. The flow arrows are dashed and extend over most of the length of the various aquifers to emphasize the overall sluggish movement of formation water in this succession and the low resolution of differences in hydraulic heads due to the relatively large error associated with pressure data from DSTs. See Figure 7.1 for line of cross section.

CHAPTER 8: SYNTHESIS

This chapter intends to summarize the hydrogeological interpretation from the various hydrostratigraphic groups in the study area in a combined conceptual flow model for the entire sedimentary succession. Changes in flow patterns and formation water chemistry from the ground surface to the Precambrian basement reflect the different flow-driving mechanisms that are or were active in the various hydrostratigraphic groups (Tab. 8.1), differing origins and evolution of the formation waters, and how the flow systems interact(ed) with each other. This flow interpretation will be put in perspective to the basin evolution, and will be compared to the prevailing basin-scale interpretations of flow in the Alberta Basin.

Stratigraphy	Hydrostratigraphic Group (HSG)	Flow-driving Mechanisms	Hydrochemistry	Water Type		
Belly River Fm.	Tertiary-Cretaceous	Topography-driven flow (local-regional scale)	Meteoric water	Ia		
Colorado Gp.		Erosional rebound	Mixing between sea- and meteoric	Ib		
Mannville Gp.		Hydrocarbon generation	Evaporated seawater altered by water-rock interaction (dissolution) and mixing with freshwater	Ic		
Fernie Gp.				II		
Permo-Triassic	Mississippian-Jurassic	Topography-driven flow (basin-scale)				
Mississippian						
Devonian	Cambrian-Devonian	Topography-driven flow (basin-scale)	Evaporated seawater, altered by water-rock interaction (albitization, dolomitization, halite dissolution)	III		
Cambrian		Strong buoyancy effects				

Table 8.1: Generalized hydrogeological characteristics of the studied sedimentary succession in west-central Alberta. The water types in the last column refer to Figure 8.1.

8.1 Origin and evolution of formation waters in the study area

Most sediments in the stratigraphic succession were deposited in a marine to marginal-marine environment and, therefore, the respective formation waters probably started out as seawater that was successively altered by water-rock interaction and mixing with freshwater during sediment burial. Hence, the main water end members are seawater and freshwater, which have relatively well defined ranges in salinity and Na/Cl-ratio: Seawater: TDS = 35 g/l, Na/Cl = 0.85; meteoric water: TDS ~ 0 - 10 g/l, Na/Cl >> 1 (because typically other anions than Cl^- , i.e., HCO_3^- , SO_4^{2-} , are dominant in shallow groundwater in the study area (Barnes, 1977; 1987; Tokarsky, 1977). The formation waters in the three major hydrostratigraphic groups in the study area have distinctively different ranges in salinity and Na/Cl-ratio, and can be grouped accordingly (Fig. 8.1), confirming the initial hydrostratigraphic delineation based on fluid flow characteristics.

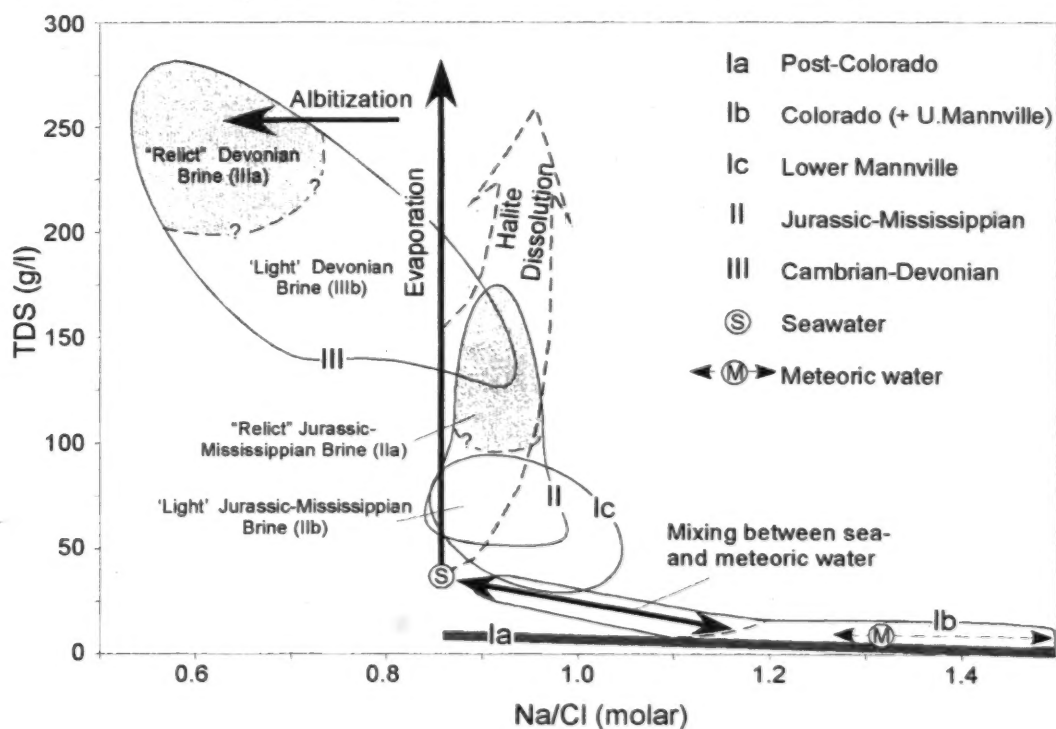


Figure 8.1: Grouping and schematic evolution of formation waters in west-central Alberta with respect to their variations in salinity and Na/Cl-ratio. See Figures 5.37, 6.19 & 7.25 for data distribution.

Generally, formation waters from the Tertiary-Cretaceous hydrostratigraphic group (Ia and Ib), except in the Lower Mannville, have salinities below that of seawater and a relatively wide range in Na/Cl-ratios (0.85-1.5); those from the Jurassic-Mississippian hydrostratigraphic group (II) and the adjacent Lower Mannville (Ic) have a salinity above that of seawater and a narrow range of Na/Cl-ratios (0.85-1.0); and the Devonian waters (III) have very high salinity and low Na/Cl-ratios (0.5- 0.9). The main processes that cause an increase/decrease in salinity are evaporation/dilution and dissolution/precipitation. The Na/Cl-ratio indicates the relative contents of the main sodium and chloride minerals, e.g., NaCl, CaCl₂, and NaHCO₃ in solution. Shallow groundwaters are mainly Na-Ca-HCO₃ type waters, therefore the Na/Cl-ratio is much larger than 1. Seawater, evaporated seawater, and deep formation water are of the Na-Cl type and have a Na/Cl-ratio around one. Formation waters that contain high concentrations of dissolved CaCl₂, hence low Na/Cl-ratio, are mainly found in aquifers in or in contact with crystalline rocks, and are probably formed by the albitization of plagioclase, exchanging Na for Ca.

Originating in a marine to marginal-marine environment, formation waters in the Tertiary-Cretaceous succession (Brazeau-Belly River to Upper Mannville) probably started out as brackish water or seawater that was successively diluted with fresh, meteoric water. The presently relatively high salinities, only slightly lower than seawater salinity, in the Upper Mannville to Cardium aquifers indicates that an effective penetration of meteoric waters did not start before the end of deposition of the Colorado shales, which partly isolate(d) these aquifers from the flushing with meteoric water since pre-Laramide time. Only those parts of the Cardium and Dunvegan aquifers that are connected to the ground surface north of the study area, where these formations crop out, contain waters with significantly lower salinity and a meteoric Na/Cl-signature. On the other hand, the Brazeau-Belly River aquifer has been effectively diluted by meteoric water, and distributions of hydraulic heads show that a flow system driven by regional-to

local-scale topography is presently active in this aquifer. The Lower Mannville sediments were deposited in a mainly fluvio-deltaic environment, but the current salinity of formation waters is up to three times that of seawater. This high salinity could be explained by leakage of brines from the Mississippian-Jurassic hydrostratigraphic group, driven vertically upward by sediment compaction, and/or mixing with high-saline, ascending Cambrian-to-Jurassic brines in areas where the intervening Exshaw-Banff and Fernie aquitards are missing due to erosion.

Having started out with seawater, aquifers in the Jurassic-Mississippian (II) and Cambrian-Devonian (III) hydrostratigraphic groups probably never were influenced significantly by meteoric water, as indicated by their high salinities. The main reason for that could be the lack of a topographic relief during and shortly after deposition of these sediments, as well as the presence of shale and evaporitic aquitards. Also, halite deposits in the Triassic Charlie Lake Formation indicate that parts of the original seawater had evaporated up to the point of halite precipitation. This suggests that formation waters in the Jurassic-Mississippian succession were partly formed by the evaporation of seawater. Nevertheless, the distribution of other major ions implies that other processes, such as precipitation of dolomite cements and dissolution of sulphate and halite, altered the composition of these waters.

Major salt deposits in the Devonian Elk Point Group northeast of the study area suggest that waters in the Devonian-Cambrian succession have a similar origin and evolution as the Jurassic-Mississippian waters. A higher degree of evaporation and additional dissolution of halite during burial probably caused the much higher salinity of the Devonian formation waters. The shift in the Na/Cl-ratio towards lower values is most likely due to the albitization of feldspar and suggests that these waters might have re-fluxed through the Cambrian clastics and/or the Precambrian crystalline basement. Hydrothermal convection in this part of the basin was invoked to explain the massive replacement of Devonian limestones by dolomite (Spencer, 1987; Wendte et al., 1997).

8.2 Flow patterns from the ground surface to the Precambrian basement

After a critical review and discussion of representation methods for flow of variable-density brines in sloping aquifers (Chapters 2 and 3), equivalent hydraulic heads were calculated based on the mean formation water density in each hydrostratigraphic group (HSG) as reference density, and used to interpret flow in the various aquifers. Freshwater hydraulic heads were used only in the Tertiary-Cretaceous HSG, after driving-force ratio (DFR) calculations confirmed density-effects are negligible. For the Jurassic-Mississippian and Cambrian-Devonian HSGs, the respective average brine density was used as a reference density for calculating hydraulic heads. The results, as presented in Chapters 5-7, confirm that the initial subdivision of the stratigraphic succession into three main hydrostratigraphic groups is correct. The three groups are (Tab. 8.1; Fig. 8.2): 1) Tertiary-Cretaceous, 2) Mississippian-Jurassic, and 3) Cambrian-Devonian. The thick intervening shale aquitards of the Fernie Gp. and the Exshaw-Banff Formations effectively impede cross-formational hydraulic communication between the Tertiary-Cretaceous and the Jurassic-Mississippian, and between the latter and the Cambrian-Devonian HSGs, respectively. This vertical isolation from each other caused flow patterns to evolve separately in the three hydrostratigraphic groups, as the respective flow systems were/are subject to different internal and boundary conditions.

The Tertiary-Cretaceous HSG can be subdivided further into the post-Colorado aquifer system, the Colorado aquitard system (Type Ib water) and the Mannville aquifer system (Fig. 8.2). The flow has adjusted to the present-day ground surface topography only in the post-Colorado aquifer system (Type Ia water). The Colorado and Mannville aquifers (Type Ib & Ic waters) are mainly cut-off from meteoric recharge by the Colorado shales aquitard, except for a tongue of freshwater (Type Ib water, TDS < 15 g/l, Na/Cl > 1.2) in parts of the Cardium and Dunvegan aquifers (Fig. 8.3) that are connected to outcrop north of the study area.

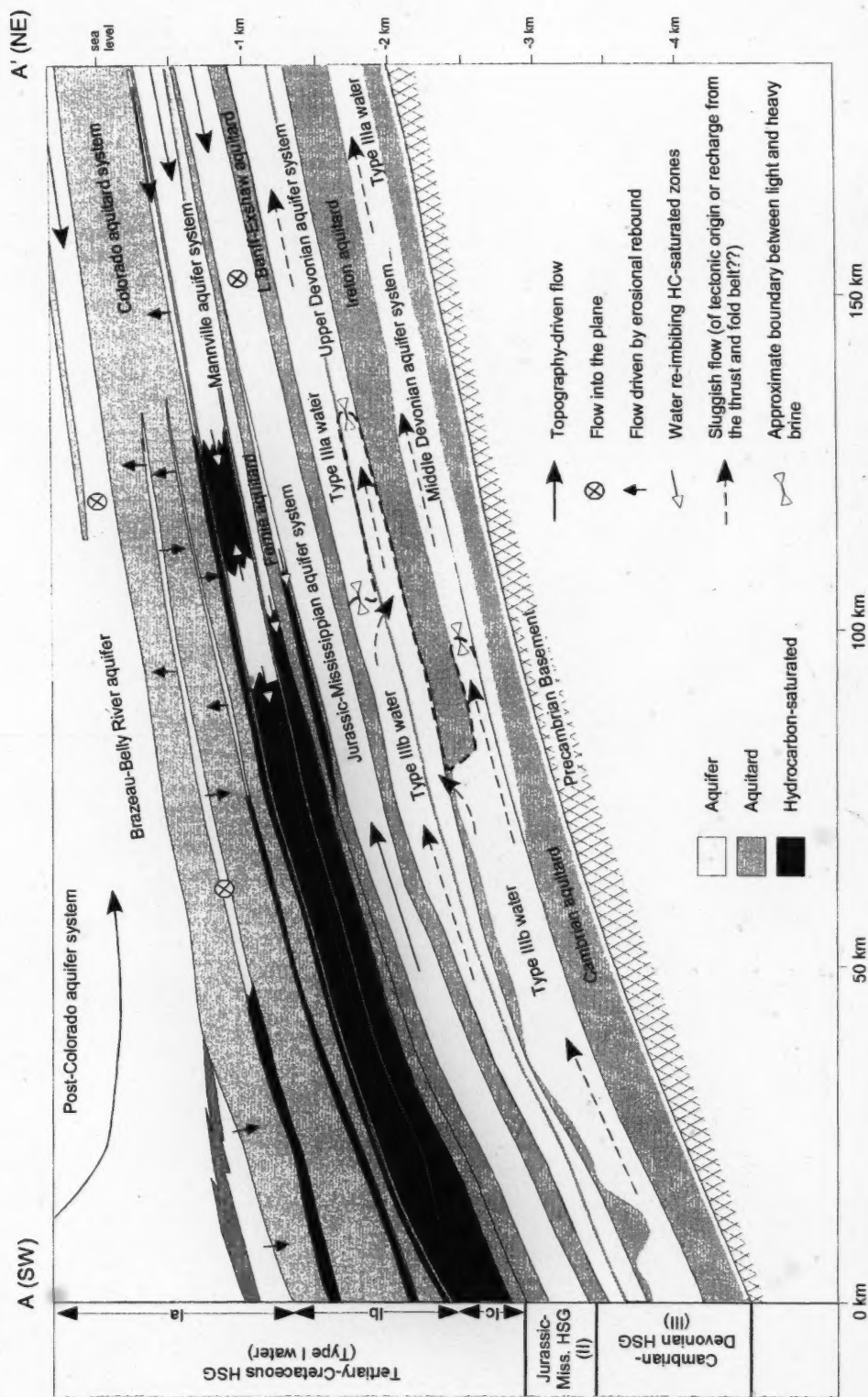


Figure 8.2: Hydrogeological dip cross section (A-A') showing the inferred flow patterns in the three hydrostratigraphic groups in the study area. (See Fig. 8.4 for line of cross section.)

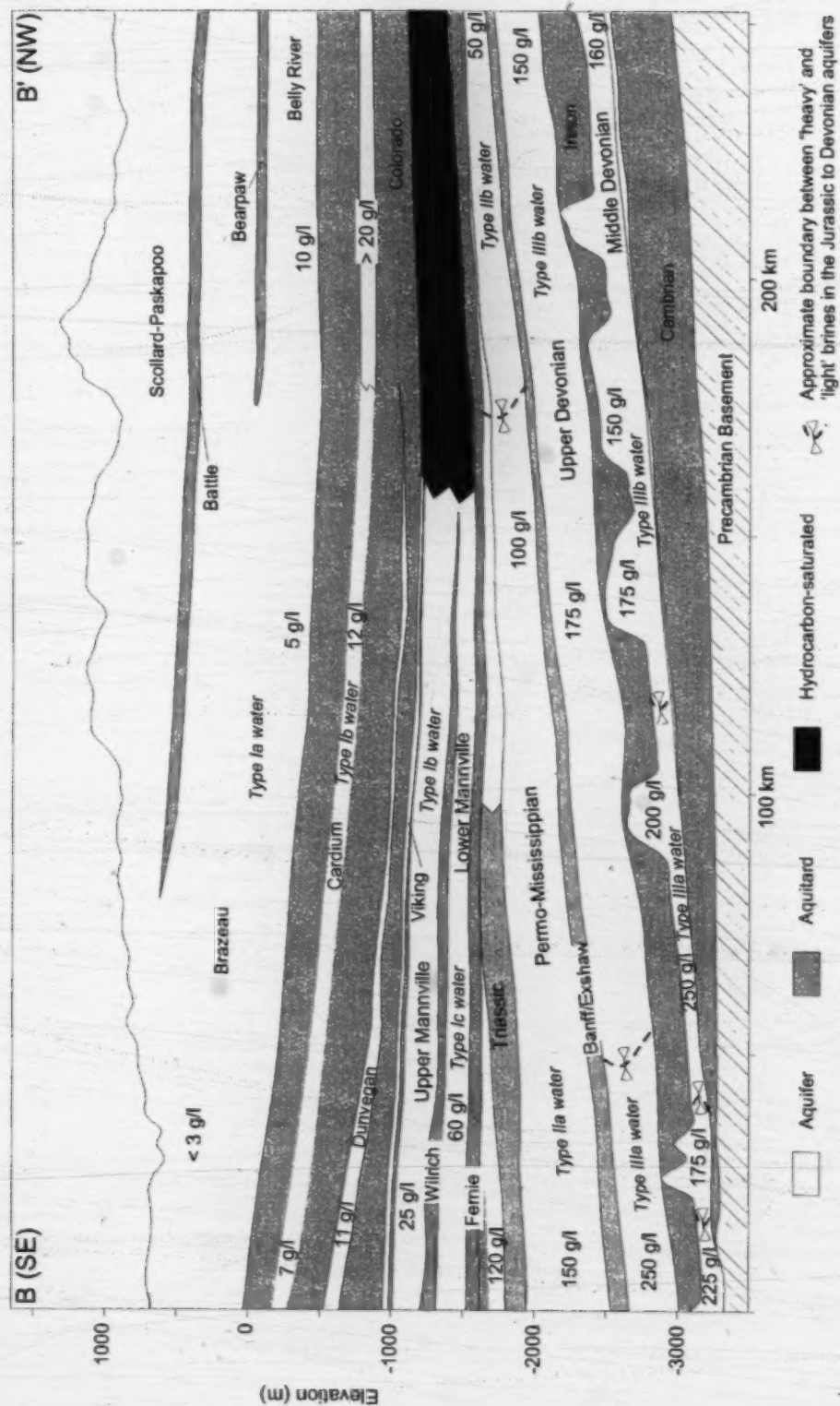


Figure 8.3: Hydrostratigraphic cross section sub-parallel to the deformation front showing general salinity distribution in the study area. (See Fig. 8.4 for line of cross section.)

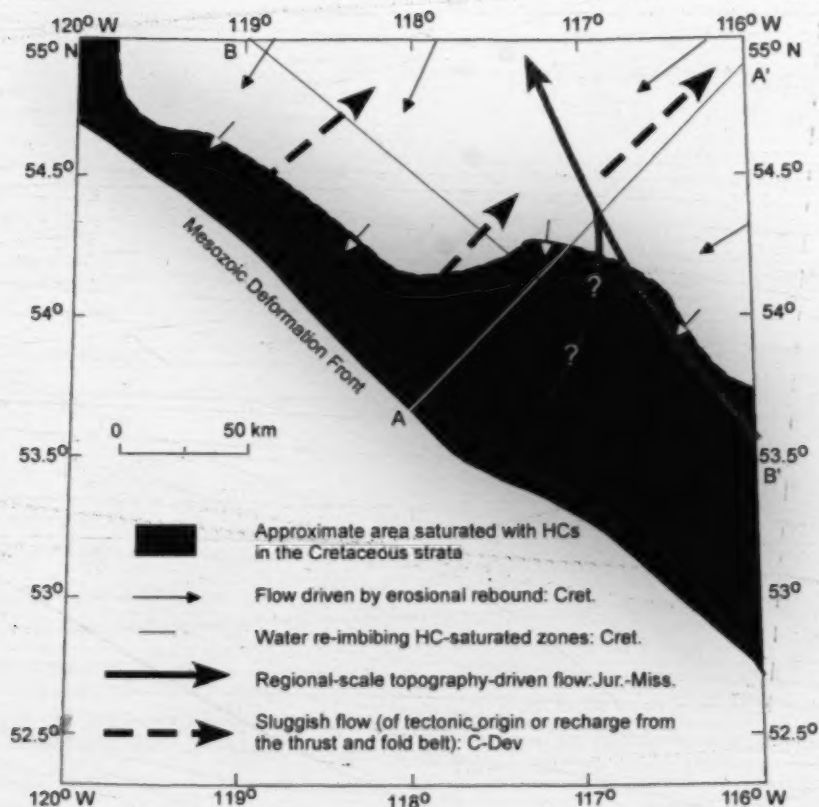
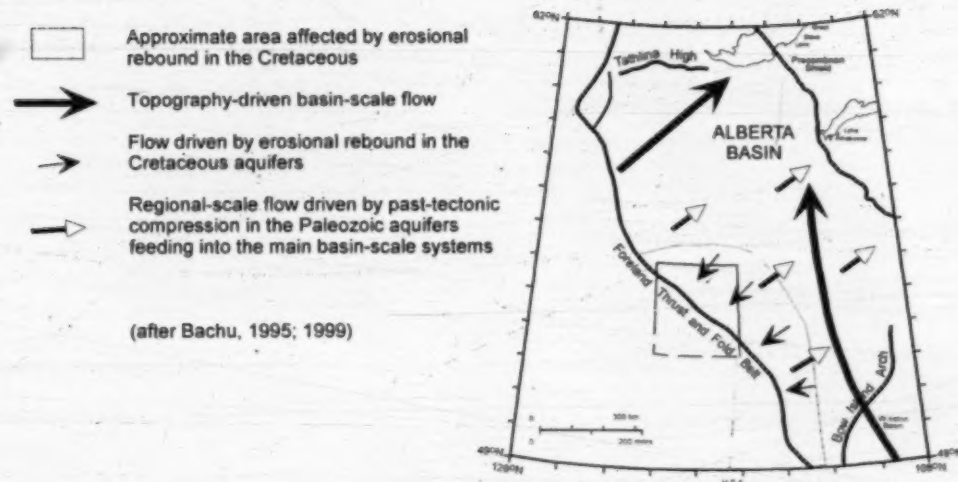


Figure 8.4: Diagrammatic representation of the flow systems and patterns in the study area compared to Bachu's (1995a, 1999) interpretation of flow in the Alberta Basin.

Burial of the basin strata and subsequent hydrocarbon generation during the Laramide orogeny created dominantly hydrocarbon-saturated zones in the deeper parts of the Mannville to Brazeau-Belly River aquifers, the hydrocarbons being located downdip of the water-saturated zones (Figs. 8.2 and 8.4). The hydrocarbon-water interface appears to be a transient permeability barrier that moves downdip towards the deformation front since the uplift of the basin and a decrease in the rate of hydrocarbon generation, while formation water could re-imbibe formerly hydrocarbon-saturated zones of these strata. Formation water flow in the Mannville and Colorado aquifers is mostly towards the receding hydrocarbon-saturated regions and towards the sinks created by erosional and post-glacial rebound of the intervening shales. In general, the hydrocarbon-saturated region represents a relative-permeability and pressure barrier with respect to lateral hydraulic communication within each aquifer, and to vertical cross-formational flow from the underlying Mississippian-Jurassic hydrostratigraphic group, and to potential meteoric recharge from the thrust and fold belt. As a result of the latter, overpressures in the hydrocarbon-saturated zones in the deep parts of the basin could be due to the weight of the overlying water column in the foothills region. An alternative, frequently employed interpretation for the cause of overpressures in hydrocarbon-saturated regions according to the literature is the active thermogenic generation of hydrocarbons in a low-permeability environment (Hedberg, 1978; Spencer, 1987; Osborne and Swarbrick, 1997).

The Mississippian-Jurassic hydrostratigraphic group represents a single continuous carbonate-sandstone aquifer system in the eastern half of the study area. The general flow direction is northward (Fig. 8.4), while fresher water (Type IIb water, TDS ~ 50 g/l) in the southeast (Fig. 8.3), which is part of a basin-scale, gravity-driven flow system originating at high formation outcrops in Montana, flows around and partly displaces a plume of connate brine (Type IIa water). Only the Permo-Mississippian aquifer continues westwards, whereas the lithology in the overlying Triassic Montney and Doig Formations changes to siltstones and shales, forming an aquitard. Overlying the Doig-Montney aquitard is the Charlie Lake-Halfway aquifer. Flow in this aquifer is eastward and, at its subcrop edge appears to be forced upward through the Fernie shales into the Lower

Mannville aquifer, where it causes an increase in formation water salinity (Fig. 8.3). A "deep basin" hydrocarbon accumulation with relatively low hydraulic heads in its vicinity is observed in the aquifer-aquitard transition zone in the Montney, similar to directly overlying hydrocarbon reservoirs in the Lower Mannville aquifer. No hydrocarbon-saturated zones were identified in the Permo-Mississippian aquifer; hence hydraulic communication of formation water between the deformed and undeformed parts of the Alberta Basin becomes possible, but has to be confirmed by further research. The hydraulic head distribution actually indicates that there is a component of flow from the direction of the thrust and fold belt of the Rocky Mountains in the central part of the study area (Figs. 6.10 & 8.4). Nevertheless, the nature and origin of this flow is still under debate (Bachu, 1999; Underschultz and Bartlett, 1999).

Similar to the overlying Mississippian-Jurassic HSG, two types of brines were identified in the Cambrian-Devonian HSG, although the salinity is generally much higher. A 'heavy' connate brine (Type IIIa water, Fig. 8.1) was probably generated from evaporated Devonian seawater and subsequent alteration due to water-rock interaction, whereas a 'light' brine (Type IIIb water, Fig. 8.1) is found mainly downdip of the heavy brine. The lighter brine attempts to flow updip, along large-scale "fingers" that are due to channeled flow along high-permeability pathways. These conduits are probably caused by lithology changes, which are controlled by the depositional facies distribution and by dolomitization. The density contrast between the light and heavy brines creates buoyancy forces, which additionally impede the flushing of the high-saline connate brine. Mixing with less saline water from overlying aquifers is only possible through lateral flow from areas southeast of the study area, where the Exshaw-Banff aquitard is absent due to erosion, or through flow from the thrust and fold belt, where faults might represent conduits to flow. In the latter case, the less saline formation water along the deformation front would represent a mixture of meteoric water and/or less saline formation water with the original connate ('heavy') brine. Furthermore, these waters probably contain a metamorphic component, because tectonically expelled fluids were might have been involved in the mixing process (Machel and Cavell, 1999). Alternatively, at least in the southeast of the study area, where the light brine appears to flow updip from the south,

the formation waters consist of Mississippian seawater mixed with Laramide – Pliocene (or present-day?) meteoric water that is part of a long-range, gravity-driven flow system originating in Montana (Bachu, 1995a). Although tectonic compression has caused the lateral expulsion of fluids from the sediments in the thrust and fold belt and the crystalline basement up to 100 km into the undeformed part of the basin (Machel and Cavell, 1999), excess pressures from this process probably have dissipated by now. Therefore, formation water flow in the Cambrian-Devonian appears to be presently controlled by basin-scale topography and buoyancy, resulting in almost stagnant conditions (Figs. 8.2 and 8.4). The recharge areas are at high elevation in Montana and, probably to a lesser extent, the thrust and fold belt of the Rocky Mountains. Discharge occurs along the sub-Cretaceous unconformity east of the study area, where Devonian and Cretaceous aquifers are in direct hydraulic communication and Devonian brines form a high-saline plume in the Mannville aquifer (Hitchon et al., 1990; Rostron and Tóth, 1997; Anfort et al., 2001).

8.3 Basin history and fluid flow evolution

It is difficult to reconstruct flow patterns during the Cambrian to Devonian stage of basin evolution. It is likely that topography-driven flow and meteoric recharge during that time were negligible, because the sediments in the study area were mainly deposited in a marine environment (platform-margin stage). Freshwater that might have accumulated during the period of erosion from the Late Cambrian to the Early Devonian, probably was displaced by descending, heavy evaporitic brines that formed during the Elk Point time. The main indication that large amounts of water must have migrated through the Devonian sediments is the massive dolomitization of limestone observed in this succession, which required an extensive flux of Mg-rich fluids. However, the flow-driving mechanisms behind the dolomitization process and the source of Mg-bearing fluids are still being debated; hence remain unclear (Mountjoy, 1994), and are beyond the scope of this study. The herein presented hydrogeological data only suggest that evaporated Devonian seawater migrated through the Devonian carbonate aquifers, and

probably also through the Cambrian succession and the Precambrian crystalline basement, where the fluids interacted with the surrounding rock framework. The resulting "relict" brines are still present in most parts of the Cambrian-Devonian hydrostratigraphic group in the study area. These observations agree with dolomitization models that involve a flow system driven by density differences, e.g., a) the long-range, down-dip migration of heavy evaporitic brines from the Williston Basin (Chipley and Kyser, 1991), or b) local-scale hydrothermal convection of evaporitic brines (Spencer, 1987, Wendte et al. 1997). An additional flow-driving mechanism during the Devonian was probably sediment compaction, which also was proposed as a possible hydraulic pumping mechanism for dolomitizing fluids (e.g., Machel and Anderson, 1989).

Marine sedimentation continued during the Mississippian, and buoyancy and sediment compaction are the most likely flow-driving mechanisms that have been active during that time. Similar to the Devonian brines, chemistry of the Triassic to Mississippian brines currently observed in the study area suggest that these represent concentrated evaporated seawater, which was altered mainly by water-rock interaction. However, the salinity of these waters is significantly lower than the salinity of the Devonian brines, one reason being that the degree of evaporation during the Mississippian-Jurassic was relatively low, as indicated by the smaller volume of evaporites in the Triassic compared to the Elk Point Group. Also, the Mississippian to Jurassic formation waters had less time to interact with the rock framework and to dissolve solids. The Triassic-Mississippian aquifers were exposed to potential meteoric recharge during the marine regressions in the Pennsylvanian, Late Permian, and Late Triassic to Early Jurassic. Therefore, mixing of formation water with freshwater during these periods could be an additional cause for the salinity in the Mississippian-Jurassic HSG being significantly lower than in the Cambrian-Devonian HSG. However, the flushing of Mississippian to Cambrian aquifers with freshwater was impeded by presumably low topographic relief; hence low potential for topography-driven flow, combined with the buoyancy between light meteoric water and heavy connate brine.

The emerging cordillera of the Rocky Mountains in the northwest at the end of the Jurassic and Early Cretaceous started to significantly change the depositional environments, formation water origin, and flow-driving mechanisms in the Alberta Basin. The generally low formation water salinity not only suggests mixing with fresh meteoric water, but also reflects the marginal-marine to marine, and, to a lesser extent, fluvial depositional environments, which result in the lack of evaporitic deposits.

During the late Jurassic, in the early stages of the Columbian orogeny, compaction continued to be the main driving mechanism for fluid flow in the basin fore-deep. Fluids were driven out of the shallow-marine shales and shelf sands, and laterally away from the basin center toward the flanks, in systems characteristic of compacting sand-shale successions (Magara, 1976a; Bredehoeft et al., 1988). In the early Cretaceous, during the deposition of the Mannville Group siliciclastic succession, local gravity-driven flow systems developed after tectonic thrusting provided higher topographic elevations in the west. These flow systems must have been relatively short lived, as the following lull in tectonic activity, represented by the deposition of the marine Colorado shales, again resulted in a compaction-dominated flow system.

The continental post-Colorado Upper Cretaceous and Tertiary strata were deposited during the Laramide orogeny. Tectonic compression, due to successive over-thrusting of foreland basin strata caused by the eastward advancement of the Cordilleran deformation front, drove laterally the flow of connate formation waters in the deeper aquifers (Garven, 1989; Ge and Garven, 1989; Deming et al., 1990). This tectonically-driven flow probably occurred in pulses and was relatively short-lived (Deming and Nunn, 1991), and, therefore, involved low average fluxes, while the respective fluids were expelled only up to 100 km laterally into the basin away from the deformation front (Machel and Cavell, 1999; Buschkuehle and Machel, 2001). Additionally, compaction of the shale-dominated Colorado succession continued to play an important role in expelling formation water (Bekele et al., 2000). Topography became increasingly important as a flow-driving mechanism at least in the post-Colorado aquifer system, setting up a northeastward

regional flow system (Garven, 1989) sub-parallel to the tectonic expulsion of formation waters.

During the Laramide orogeny, almost the entire sedimentary succession from the Cretaceous to the Cambrian entered the oil and subsequently the gas window, reaching a maximum burial in the Eocene (Bustin, 1991; Kalkreuth and McMechan, 1996). Overpressures developed specifically in the deep Colorado and Mannville strata as a result of compaction and hydrocarbon generation (Hedberg, 1974; Spencer, 1987; Osborne and Swarbrick, 1997; Bekele et al., 2000). Gas and oil displaced the formation water from the pore space in the deep Cretaceous strata adjacent and sub-parallel to the deformation front, forming a pressure and relative-permeability barrier for formation water flow. Since the peak of the Laramide orogeny, the basin has been uplifted due to tectonic relaxation and erosion to the present-day topographic relief. As a result, the oil and gas windows shifted downward, and the rate of hydrocarbon generation decreased in the Cretaceous succession. At present, only the deep part of these strata still generates gas or oil, maintaining high pressures and hydrocarbon saturation in the Cretaceous aquifers. In regions further updip, the rate of hydrocarbon loss and pressure dissipation is higher than the replenishment by hydrocarbon generation, allowing formation water to re-imbibe the "deep basin" reservoirs along the boundary between hydrocarbon – and water-saturated zones (Figs. 8.2 and 8.3). This effect, combined with the erosional rebound of thick shales, led to significant underpressures in hydrocarbon- as well as water-saturated regions because, as a result of very low fluid fluxes in a low-permeability environment, water is not capable of replenishing the expanding pore space. Therefore, the regional flow pattern was reversed from an eastward-directed compaction- and topography-driven system to a westward direction of flow driven by erosional rebound and hydrocarbon leakage in the Colorado and Mannville aquifers.

8.4 Hydraulic communication between deformed and undeformed parts of the Alberta Basin

The interpretation of basin evolution and fluid flow introduced above shows that only in the early stages of the Laramide orogeny there existed the possibility of formation water flow from the deformed into the undeformed parts of the Alberta Basin throughout the entire sedimentary succession. The high elevation of the orogen represented the recharge area of a basin-scale topography-driven flow system, and tectonic compression caused basin-ward expulsion of fluids. Although the topographic high and, therefore, a potential for fluid flow still exist in the foothills and front ranges of the Rocky Mountains, the hydrocarbon-saturated region in the deep Cretaceous strata has formed a permeability barrier for water flow since approximately the Eocene. Only flow above the Colorado shale aquitard is driven by the local to regional topography and the potential flow from the foothills and front ranges in this succession is restricted to the near vicinity of the Cordilleran deformation front. The underpressures observed in the Mannville, Colorado and Brazeau-Belly River aquifers cause formation water to flow from the plains region towards the mountains, opposite to the high fluid potential in the mountains, suggesting that the two regions are hydraulically disconnected.

On the other hand, the present flow in the Mississippian-Jurassic and Cambrian-Devonian HSGs adjacent to the deformation front is directed northeastward, updip, and therefore is coincident with high fluid potential in the foothills and front ranges of the Rocky Mountains. Also, formation water salinity is relatively low, although still higher than that of seawater, suggesting at least the possibility of mixing with meteoric waters that penetrate the deep aquifers via convoluted pathways along faults in the deformed belt. However, hydrogeological data west of the deformation front are too sparse to corroborate this interpretation. One noteworthy argument against a notable influence/effect of meteoric recharge from the area of the Rocky Mountain is the south-north directed basin-scale flow system originating in Montana (Bachu, 1995a; Anfort et al., 2001). Although the topographic highs and the recharge area in Montana are at much

greater distance from the study area than the directly adjacent Rocky Mountain thrust and fold belt to the southwest, the pattern of relatively fresher water flowing into the study area along the north-to northwest flow direction is dominant or at least equal to the updip flow of water with comparable salinity.

In summary, hydraulic communication between the deformed and undeformed parts of the Alberta Basin is possible according to the presented hydrogeological data, but it only affects the flow in the basin at a distance of approximately 100 km from the deformation front of the Rocky Mountains. Further research and more comprehensive hydrogeological data from the region of the thrust and fold belt of the Rocky Mountains is needed to resolve this issue.

8.5 Summary of original scientific contributions

This study tried to resolve remaining questions on fluid flow in the west-central part of the Alberta Basin adjacent to the Rocky Mountain thrust and fold belt. This resulted in original contributions to the understanding of flow, origin and evolution of formation waters in the Alberta Basin, which also has implications for the study of regional fluid flow in foreland basins in general. The following aspects are considered particularly worth mentioning:

- (1) Errors in the flow representation of variable-density brines could be minimized using the average formation water density as reference density in the calculation of hydraulic heads, which is an alternative to the calculation of driving-force vectors. A comparison of the two methods, using actual pressure and hydrochemical data, showed that the sum of mechanical and analytical errors associated with the hydrogeological data outweigh the theoretically higher accuracy of driving-force vectors. In most areas where the possibility of flow reversal exists, the accuracy of the hydrogeological data only allows interpreting the respective flow pattern as $\pm$

stagnant, even when using the theoretically accurate driving force vectors. While driving force vectors are theoretically more accurate than hydraulic heads, additional technical and procedural errors are introduced, because the calculation of driving force vectors requires the computation of water densities from salinity data in addition to the pressure data, and the actual calculation of gradients between wells or within a grid of inter- and extrapolated data.

- (2) The formation waters from the various hydrostratigraphic groups in the study area could be subdivided into four groups, and characterized as: 1) mainly fresh, meteoric water, 2) mixing between seawater and meteoric water, 3) evaporated seawater concentrated by halite dissolution and 4) evaporated, concentrated seawater significantly altered by the albitization of feldspar.
- (3) This study is the first to identify the interaction between "deep basin" hydrocarbon-saturated and water-saturated zones in the Cretaceous aquifers as an additional mechanism to create underpressuring in the Alberta Basin. Also, the hydrocarbon-saturated zones represent a regionally extensive, effective relative permeability barrier to flow from the Rocky Mountain thrust and fold belt.
- (4) Combining the interpretation of flow and formation water chemistry shows that Jurassic-Mississippian and Cambrian-Devonian formation waters in the deep, west-central parts of the Alberta Basin have been influenced less by mixing with meteoric water than in the central, southern and northern parts of the basin, than previously identified by Connolly et al. (1990), Schwartz et al. (1981), and Bachu (1997), respectively. The main reasons for the isolation of "relict" formation waters in the deep Alberta Basin are effective confining aquitards, sluggish flow, and the fact that this area is influenced only marginally by mixing with meteoric water carried by a gravity-driven flow system.
- (5) The boundary between a 'light' and a 'heavy' brine in the Mississippian to Devonian aquifers appears to represent a front of less saline formation water displacing the original connate brines, both along the deformation front and in the southeast of the study area. Similar patterns of formation water salinities and hydraulic-head distributions could be correlated with regional lithofacies maps, which shows that this

displacement occurs along preferential flow paths, i.e., the platform margins of the Southesk-Cairn and Swan Hills carbonate complexes.

- (6) Present flow in the Devonian aquifers is almost stagnant due to buoyancy effects between less saline formation water being located downdip of heavy connate brine counteracting the regional potential for updip flow and the lack of another active flow-driving mechanism.

8.6 Future work

There are still remaining issues on the hydrogeology of the Alberta Basin, including the study area, that should be addressed in future research.

- In general, more hydrogeological data is needed from the Rocky Mountain thrust and fold belt to better understand the flow systems within the deformed part, and the hydraulic communication with the undeformed part of the Alberta Basin.
- Future numerical modeling studies of flow in the basin should account for the effectively low permeability of the hydrocarbon-saturated regions and try to quantify their effect on underpressuring.
- Permeability data and parameters describing the two-phase relations between hydrocarbons and formation water (saturation indices, relative permeability) are needed for further quantitative studies on the interaction between hydrocarbon- and water-saturated zones.
- Also, permeability values should be determined from drillstem test data for the Cambrian to Jurassic strata to quantify the sluggish movement of the deep formation waters.
- Additional work on isotope data from deep formation waters adjacent to the deformation front would improve the identification of brine components that are of possible meteoric, metamorphic, hydrothermal or other origin.

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APPENDIX A: A BRIEF REVIEW OF FLOW DRIVING MECHANISMS FOR AQUEOUS FLUIDS IN SEDIMENTARY BASINS

Introduction

The purpose of this chapter is to review the driving mechanisms for formation water flow in sedimentary basins and to assess methods of flow representation, especially for variable-density fluids in sloping aquifers.

In contrast to near-surface groundwater flow, which is almost solely driven by gravity in most cases, regional flow in sedimentary basins is driven by a combination of various mechanisms such as: a) topography (gravity), b) sediment compaction, c) tectonic loading, d) erosional rebound, e) buoyancy, f) overpressures due to hydrocarbon generation, and g) osmosis or mineral phase changes. During the geological history of a sedimentary basin various driving mechanisms may be dominant in various stages of basin evolution. Therefore, this review examines the individual driving mechanisms, as well as fluid and rock properties with respect to their influence on basin-scale fluid flow.

Flow driving mechanisms

It is generally accepted that one of the most important driving mechanisms for fluid flow at various scales in continental sedimentary basins is gravity, and that flow is controlled by the ground surface topography (e.g., Tóth, 1963; 1995; Senger and Fogg, 1987; Kreitler, 1989; Deming and Nunn, 1991; Bjorlykke, 1993; Garven, 1995). Topography-driven flow may be active almost throughout the entire basin history (Fig. A1, a-e) and is generally the main driving mechanism for shallow groundwater flow. Other flow-driving mechanisms become significant only in low-permeability environments and/or at greater depths with increasing temperature and salinity. They usually become important during certain stages of basin evolution.

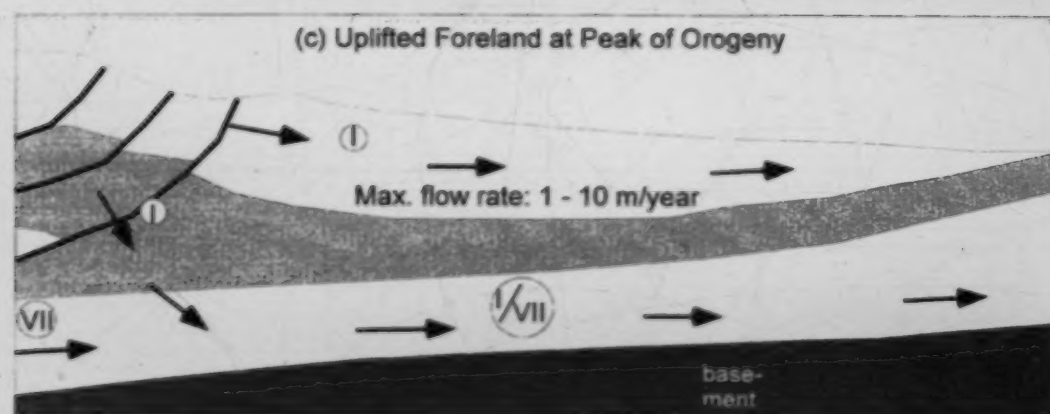
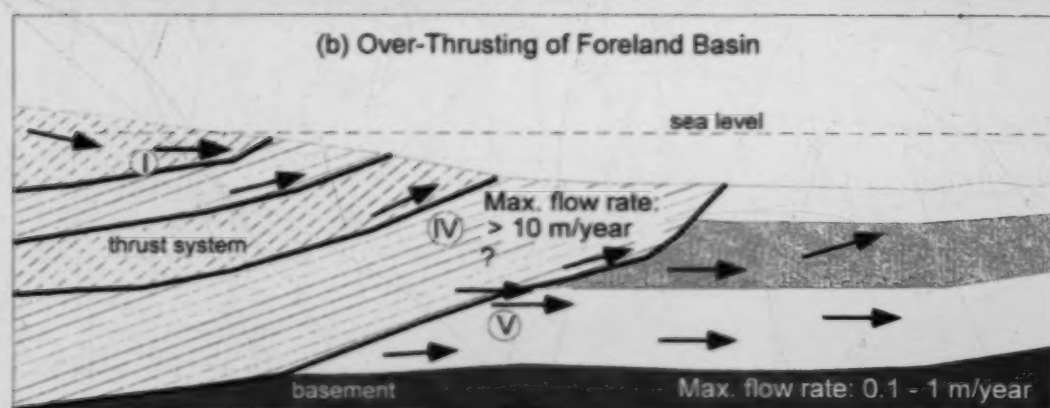
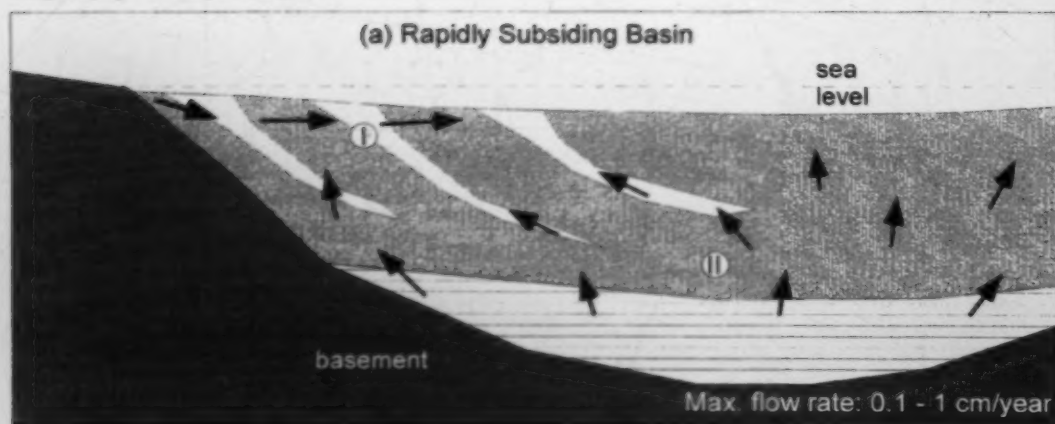


Figure A1: (continued on next page)

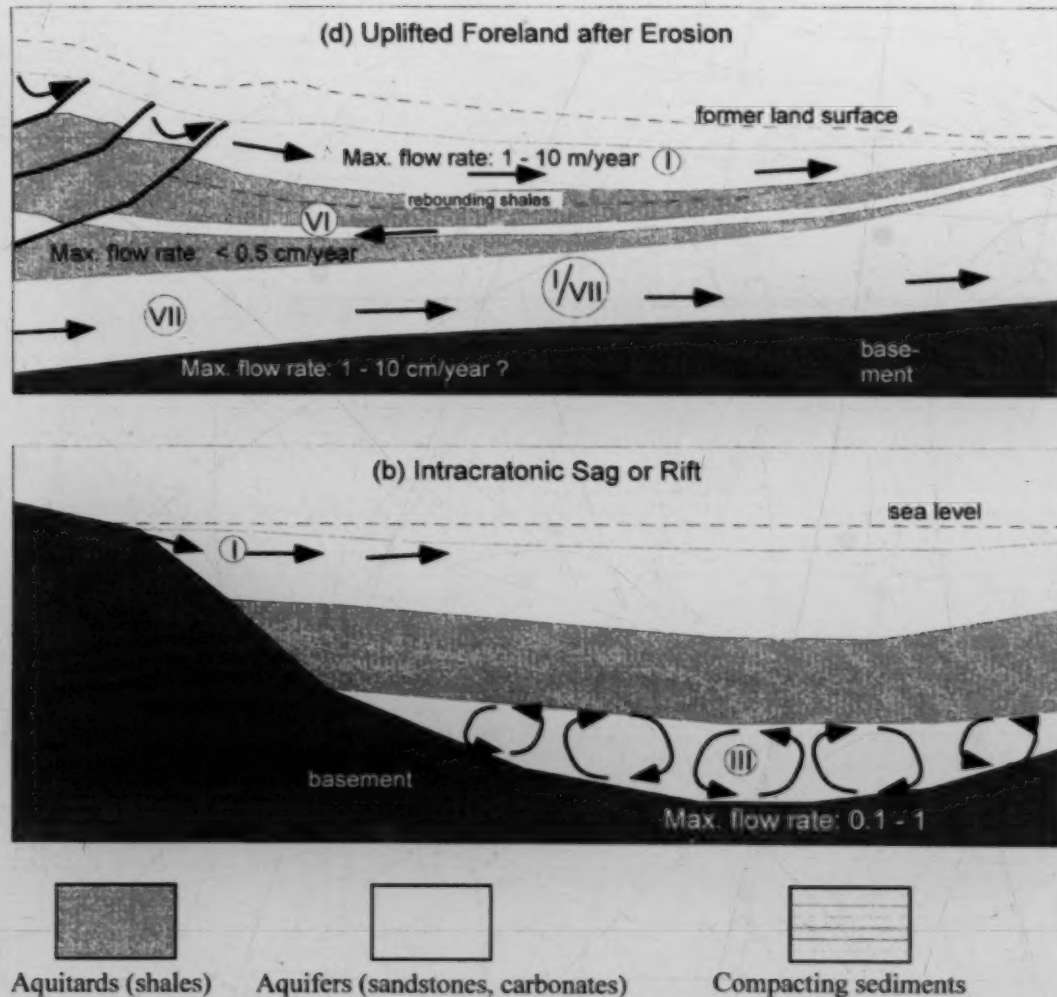


Figure A2: Conceptual representation of regional-scale hydrogeological regimes during the history of a sedimentary basin (modified from Garven, 1995). Arrows represent general flow direction. I Topography-driven flow; II Compaction-driven flow; III Thermally-driven free convection; IV Seismic pumping; V Tectonic expulsion; VI Flow driven by erosional rebound; VII Paleo-flow regime of tectonic origin or paleo-topography.

Topography- (gravity) driven flow

Studies of dominantly topography-driven systems and hydraulic continuity in sedimentary basins are abundant in the literature (e.g., Deming and Nunn, 1991; Garven, 1985; Hitchon, 1969a; Tóth, 1963, 1978, 1995). At least for shallow to intermediate depths, the potentiometric surface of hydraulic heads is generally a smoothed replica of the ground surface. This indicates that there is groundwater recharge in areas of topographic highs and water discharging in areas of topographic lows. With increasing depth the similarity between potentiometric surfaces of various aquifers and topographic relief decreases, which results in local, intermediate, and regional flow systems (Tóth, 1963). Local flow occurs from local topographic highs to adjacent lows, whereas the regional flow patterns are generated by the basin-scale recharge and discharge area(s) (from the highest to the lowest points of elevation in the basin). Hence, when studying only a part of a sedimentary basin, the recharge and/or discharge areas for the deep aquifers might not even lie within the defined study area. In addition, the architecture of the basin and the permeability distribution control the extent of the various flow systems. Thick, regionally extensive aquitards usually impede cross-formational flow, and separate different flow systems above and below. Similarly, high permeability aquifer systems will focus fluid flow in whichever part of the basin, deep or shallow, they are located (Freeze and Witherspoon, 1967).

Compaction-driven flow

An important driving mechanism in the early stages of basin evolution is compaction due to burial of the sediments and pore fluids (Fig. A1, a). Compaction is a process in which, due to the weight of overburden, porosity decreases, while pressure and temperature increase, and fluids are expelled from the reduced pore space. The increased load on the sediment column is partitioned between the mineral grains (effective stress) and the pore fluid (fluid pressure). "Normal compaction" or "compaction equilibrium" implies concurrent fluid expulsion with loading of the sediments, without apparent increase in pore pressure, in contrast to "disequilibrium compaction", where fluids are expelled some

time after the deformation process, resulting in above-hydrostatic fluid pressures (Domenico and Schwartz, 1998; p. 25). Whether normal or disequilibrium compaction prevails depends on sedimentation rate and permeability, which govern the drainage rate of the pore fluid, sediment compressibility, and rate of compaction. For normal compaction, the velocity of upward-moving pore water, controlled by the decrease in porosity due to newly added sediment, decreases from top to bottom of the sedimentary sequence and is proportional to the sedimentation rate (Einsele, 1978). In the case of a very high sedimentation rate in fine-grained sediments, the permeability is relatively low. Fluids cannot drain from the reduced pore space fast enough to let fluid pressures equilibrate to the increase in stress, which leads to overpressures in the fluid phase.

During sediment deposition in marine environments, the pore fluid is seawater. Maximum compaction occurs in the basin center, reducing the pore space and driving the pore water upwards and to the basin edges (Magara, 1976a). Meteoric water flows into the basin from topographic highs at its flanks, counteracting the direction of the compaction-driven flow, and forms a freshwater lens above the denser seawater (Fig. A1, a; Bjørlykke, 1993; Person and Garven, 1994). Relative sea level changes may serve as an additional driving mechanism caused by an increase in hydrodynamic head when the sea level is lowered (Bethke et al., 1988). Sedimentation rate, permeability of the sediments, availability of meteoric water, and topographic relief govern the depth of penetrating freshwater and the extent of displacement and replacement of connate waters. Sedimentation stops when the basin subsidence ceases, also causing an end of compaction.

Tectonic loading

Aside from the compaction caused by sedimentation, the formation of over-thrust belts (Oliver, 1986) is another mechanism that leads to the deformation of the sediment column, where, in a relatively short time period, sedimentary successions are covered under thick sheets of rocks due to tectonic movements (Fig. A1, b). The maximum flow

rates under lateral tectonic compression occur when the sediment added to the orogen is entirely accommodated by the compression of pore volume and all pore fluids escape laterally (Bethke and Marshak, 1990). In return, increased fluid pressures reduce the total stress and facilitate the tectonic movement along the fault planes (Hubbert and Rubey, 1959). Some authors (Deming et al., 1990; Bethke and Marshak, 1990; Nunn and Deming, 1991; Ge and Garven, 1992) used numerical modeling techniques and temperature distributions to prove that fluid flow by tectonic expulsion is effective only for a relatively short distance (~ 100 km) from the orogen. Their calculations predict that the induced overpressures quickly dissipate after about 10^3 to 10^4 years. As thrust belts commonly form mountain ranges, they also are major topographic highs that develop an asymmetrical topography-driven flow system with regional recharge in the mountains and fluid flow into the undeformed basin (Fig. A1, c), approximately in the same direction as the expelled fluids. A local phenomenon of fluid expulsion may occur with the rapid partial relief of shear stress that accompanies earthquakes, which drives fluids upwards rapidly along faults (Fig. A1, b, IV) in the direction of the easiest pressure release (Cosgrove, 1991).

Erosional rebound

Erosional unloading and uplift of the basin at the end and after an orogeny cause a decrease in total stress. Neuzil and Pollock (1983) suggest that this may cause formerly compressed sediments to partly rebound, causing a dilatation of the rock framework, an increase in pore space and, concurrently, a decrease in fluid pressure (Fig. A1, d). According to these authors, the sediment must have a very low permeability and a large compressive storage in order to prevent fluid pressures from equilibrating and to maintain sub-hydrostatic fluid pressures over a certain period of time. The best examples are thick, de-compacting shale units like the Cretaceous Pierre Shales in the Williston Basin (Neuzil and Pollock, 1983; Neuzil, 1993), and the Colorado shales in the Alberta Basin (Corbet and Bethke, 1992; Bachu and Underschultz, 1995; Parks and Tóth, 1995). Furthermore, the sediments should not be fractured or inter-bedded with coarser grained

layers on a regional scale to an extent that allows pressures to equilibrate via connected high permeability pathways.

It is important to note that the specific storage for compaction is larger than that for erosional rebound, because only a part of the compressive deformation of the rock framework is reversible (mechanical hysteresis). This implies that compaction has a much larger effect on fluid pressures than erosional rebound. Overall, it is relatively hard to quantify the effects of compaction, and especially those of erosional rebound, on fluid flow, because the change of many variables over time is not known. Permeability in particular changes significantly during these processes, and compaction and erosion rates are not constant, neither spatially nor over time.

Buoyancy-Driven Flow (

Buoyancy-driven flow depends only on density differences within the fluid and is coupled with the hydraulic gradient. Assuming an isotropic porous medium, pressure-related forces drive the fluid in the direction of maximum hydraulic-head gradient, whereas buoyancy drives the fluid in direction of maximum aquifer slope (Bachu, 1995b). Once there is flow due to buoyancy, the pressure field changes. Density differences may be the result of changes in: a) fluid salinity and/or b) pressure and/or c) temperature. As both salinity and temperature vary widely in sedimentary basins, buoyancy definitely has to be considered as a driving mechanism for regional fluid flow. Moving fluids can transport heat and mass by "forced convection", where flow is driven by an external force, or by "free convection", in which case buoyancy is the exclusive driving force (Domenico and Palciauskas, 1973). Cases of free convection in which density variations of the fluid are the dominant driving force have been suggested in areas around salt domes (e.g., Rangathan and Hanor, 1988), or areas associated with magmatic activity (e.g., Cathles, 1977; Sharp and Kyle, 1988). Forced geothermal convection has been invoked to explain diagenetic alterations of sandstones (e.g., Wood and Hewett, 1982) and carbonates (e.g., Hardie, 1987; Morrow, 1998).

The dimensionless Rayleigh number Ra relates buoyancy to dissipation (viscous and diffusive) forces and is generally defined as (e.g., Holzbecher, 1998, p. 83):

$$Ra = \frac{g k b \Delta \rho}{\mu D}$$

where k = permeability (m^2), b = aquifer thickness (m), μ = viscosity (cp), D = diffusivity (m^2/s), thermal or chemical, depending on whether temperature or salinity creates the density difference $\Delta \rho$. There are also cases of double diffusive processes, where both temperature and salinity vary.

For thermal convection only, the previous transforms into (e.g., Bear, 1972, p. 656):

$$Ra = \frac{g k b \rho_0 \rho c_w \alpha_f \Delta T}{\mu \kappa_e}$$

with c_w = specific heat of the fluid ($J/kg^{\circ}C$), α_f = coefficient of fluid thermal expansion ($1/^{\circ}C$), κ_e = effective thermal conductivity ($W/m^{\circ}C$).

The onset of free convection in a porous medium is generally accepted to occur for $Ra > 10$ to 40, depending on the boundary conditions (e.g., Nield and Bejan, 1992). According to Raffensberger (1997), given the right conditions, free thermal convection is favored in a relatively shallow depth range of about 500 - 2000 m, whereas at greater depths high fluid salinity dampens the opposing effect of temperature increase with depth. This is because thin sediment layers of low permeability can already significantly obstruct fluid flow. Thus, it is unlikely for regional-scale free thermal convection cells (Fig. A1, b) to develop, because sedimentary basins generally consist of layered sequences of varying permeability (Bjørlykke, 1993).

In summary, density differences have to be taken into account when interpreting regional formation water flow, because buoyancy is coupled with the hydraulic gradient and dampens or enhances flow in the direction of maximum aquifer slope. On the other hand, free convection probably is a more local-scale phenomenon and its effect on regional-scale flow is negligible.

Other flow-driving mechanisms

This section will review briefly other flow-driving mechanisms that are generally important only on a local scale, but, under certain hydrogeological conditions, may cause "anomalies" in regional flow systems. These conditions are mainly created in low-permeability environments, which are at least partly isolated from a topographic-driven flow system and allow induced pressures to dissipate only slowly. They are most likely to be found in mature sedimentary basins or basins with low topographic relief and extensive shale layers. Possible causes for abnormal fluid pressures are: a) mineral and hydrocarbon phase changes, b) mineral dissolution and precipitation, c) osmosis, and d) water derived from magmatic intrusions or the basement (Osborne and Swarbrick, 1997).

Mineral phase change reactions during increasing burial, such as gypsum to anhydrite and the transformation of clay minerals, result in a fluid volume increase due to the release of water. In the case of dehydration of gypsum to anhydrite, this volume increase is 38% compared to a 5 - 10% increase for the transformation of smectite to illite or the dehydration of montmorillonite (Bjørlykke, 1993). If fluids cannot escape the pore space fast enough, or the porosity is not increased by the expansion of the rock framework, the volume increase will lead to overpressures. According to Osborne and Swarbrick (1997), both processes are probably not responsible for significant overpressures, because the gypsum - anhydrite reaction mainly occurs during shallow burial and therefore cannot produce overpressures at greater depth. The dehydration of smectite is only responsible for a small release of water and is inhibited by a pressure buildup. A more effective source for overpressures seems to be the precipitation of cements due to the release of

ions during clay transformations, which results in decreases in porosity and permeability (Osborne and Swarbrick, 1997). A much larger volume increase in the fluid phase is generated by the phase changes from kerogen to petroleum, further from kerogen degradation and thermal cracking of liquid to gaseous hydrocarbons, and direct gas generation (Hedberg, 1974; Spencer, 1987). In addition, the effective permeability of the sediment is reduced when a second fluid phase is introduced.

Another process believed to drive fluid flow is chemical osmosis. Osmosis occurs when shales, which act as a semi-permeable membrane, separate two aqueous solutions of different salinity. The passage of anions and cations through the membrane is inhibited because of the positively and negatively charged layers of the shales. To equilibrate the chemical gradient across a membrane, neutral water molecules pass through the shale layer, resulting in a net flow of water to the more saline side of the membrane. Marine and Fritz (1981) explain pressures in excess of hydrostatic of about 100 kPa, or 10 m excess hydraulic head, in a Triassic basin in South Carolina by osmosis, which causes freshwater to pass through 30 - 300 m thick illite - rich shales and dilute the connate Triassic brines. Describing laboratory hydraulic tests on kaolinite, Olsen (1985) proposes that osmosis is responsible for non-Darcyian flow in low-permeability sediments. Like all the other mechanisms involving low-permeability environments, osmosis requires compacted, continuous, and non-fractured shale layers. However, according to Phillips (1983), shales are inefficient semi-permeable membranes. This, coupled with $K_C \ll K_H$, renders osmosis as a negligible driving mechanism for regional-scale flow (Bachu, 1995b).

Evolution of flow patterns

Pressure conditions in deep-basin aquifers do not necessarily reflect the current boundary conditions, including recharge and discharge areas and the present-day surface topography, but instead represent a transient state in which pressures created by paleo-conditions are in the process of equilibrating to the current boundary conditions. In the Alberta Basin for example, adjustment times in the order of $10^3 - 10^7$ years have been calculated for hydraulic heads in various Cretaceous aquifers embedded in major shale

aquitards (Tóth and Millar, 1983; Tóth and Corbet, 1987). Critical variables in calculations of such phenomena are the time period a certain topographic relief exists without major changes, the rate of erosion/uplift, and the permeability of the aquifers and aquitards, which change over time. For regional and basin-wide hydrogeological studies this implies that it is very likely to encounter heterochronous flow fields (Tóth, 1995), and that flow in deeper aquifers may be in a different direction than what the present-day topographic relief suggests. As long as the geometry of the sedimentary basin is subject to change due to tectonics and erosion, only fluid pressures and thus fluid flow in the near-surface aquifers would have had the time to equilibrate to the present ground surface topography.

Summary

Flow in sedimentary basins is driven by a combination of mechanisms, such as a) topography (gravity), b) sediment compaction, c) tectonic loading, d) erosional rebound, e) buoyancy, f) overpressures due to hydrocarbon generation, g) osmosis and h) mineral phase changes. The internal and boundary conditions for fluid flow change with time and various driving mechanisms may be active during different stages of the basin history. Pressure dissipation and fluid flow as a result of the various flow-driving mechanisms are transient processes, and their rates largely depend on the permeability distribution. Aquitards and lateral low-permeability barriers retard these processes so that the present-day pressures in the subsurface have not necessarily equilibrated to the present-day internal and boundary conditions. Flow systems at shallow depth usually have adjusted to the current ground surface relief and are topography-driven, while flow in deeper, low-permeability environments, which are relatively isolated from the ground surface, may be controlled by other driving mechanisms or reflect a paleo-flow regime. In regional-scale hydrogeological studies, the effect of osmosis is usually negligible and the flow can be represented and analyzed by the driving force acting on the fluid.

APPENDIX B: DRILLSTEM TEST DATA

Location in Dominion Land Survey coordinates: MMTTTRRSSLLxxxx
(Meridian, Township, Range, Section, LSD)

Date: date the DST was performed

Well ID: unique well identifier in AGS database

= DST number

S = shut-in phase of the DST

Q = quality code

z = pressure recorder elevation

dtop = depth to the top of the test interval

dbot = depth to the bottom of the test interval

H_0 = freshwater hydraulic head in metres above sea level

H_{1040} = hydraulic head in metres above sea level calculated with reference density of
1040 kg/m³

H_{1090} = hydraulic head in metres above sea level calculated with reference density of
1090 kg/m³

KB = Kelly bushing

Fluid recovery: recovered fluid from the DST in order of volume

Aquifer: aquifer unit in which DST was performed

Location	Date	Well ID	#	S	Q	p [kPa]	z [m]	dtop [m]	dbot [m]	H ₀	H ₁₀₄₀	H ₁₀₆₀	KB [m]	Fluid recovery	Aquifer
5W04816293060000	730852	35183	1	1	A	4521	446	724	759	906			1171	n/a	Pask-Coalspur
5W05619061102000	710323	-3697	1	1	A	6700	531	747	760	1214			1261	n/a	Pask-Coalspur
5W05922021000000	781006	35692	1	1	A	2063	643	488	518	853			1132	n/a	Pask-Coalspur
5W04816360700000	730401	35187	1	1	B	4844	426	700	725	920			1127	n/a	Pask-Coalspur
5W06226181100000	770130	35573	6	1	B	890	749	354	371	840			1106	n/a	Pask-Coalspur
5W05619061102000	710323	-3697	2	1	B	6880	559	719	743	1240			1281	n/a	Pask-Coalspur
5W05315300600000	731127	35070	1	1	B	1843	661	276	285	829			942	n/a	Pask-Coalspur
5W05619161600000	750721	35386	7	1	B	3780	578	531	639	964			1213	n/a	Pask-Coalspur
5W04816151000000	760204	35368	2	1	C	4849	431	716	733	936			1150	n/a	Pask-Coalspur
5W04917121100000	740621	35395	1	1	C	3766	459	681	728	843			1143	n/a	Pask-Coalspur
5W06320101000000	960859	-2202	4	1	A	7820	-31	880	880	767	736		831	water	Brazeau-B. River
5W06621151300000	960505	-2843	1	1	A	3850	290	440	452	682	667		733	water+mud	Brazeau-B. River
5W05819111400000	950227	-3017	2	1	A	11100	-349	1590	1600	783	739		1250	mud	Brazeau-B. River
5W05318140600000	720920	34879	3	1	A	13500	-809	1580	1590	769	714		975	water	Brazeau-B. River
5W05317171600000	781214	35240	2	1	A	10800	-335	1260	1270	763	724		927	water+cond.+mud	Brazeau-B. River
5W05717251100000	810610	35415	3	1	A	9870	-239	1340	1350	767	728		1110	water	Brazeau-B. River
5W04715081400000	840717	35442	3	1	A	12000	-794	2000	2000	433	382		1190	oil+mud+cond.	Brazeau-B. River
5W06718301100000	770829	35601	3	1	A	8060	-72	946	961	750	718		876	water+oil	Brazeau-B. River
5W06820121000000	770923	35672	2	1	A	2650	411	370	378	681	671		783	water+mud	Brazeau-B. River
5W06014090600000	790117	35682	5	1	A	2680	392	351	377	666	655		745	n/a	Brazeau-B. River
5W06423131100000	670312	36397	2	1	A	7820	-17	807	823	780	729		792	water	Brazeau-B. River
6W06303200900000	840306	39279	3	1	A	3450	300	555	568	652	638		866	water	Brazeau-B. River
5W04716120500000	840215	68675	1	1	A	8050	-161	1130	1150	660	628		968	water	Brazeau-B. River
5W05518260600000	861024	68678	1	1	A	11800	-822	2030	2040	382	335		1210	mud+cond.	Brazeau-B. River
5W05517360700000	880223	76709	2	1	A	11700	-420	1370	1490	768	727		1050	n/a	Brazeau-B. River
6W06504180300200	880205	80085	2	1	A	8990	-232	1130	1150	776	738		904	water+mud	Brazeau-B. River
5W06021240700000	891211	80705	2	1	A	10200	-272	1240	1240	687	651		869	water+cond.+mud	Brazeau-B. River
5W04715291500000	951202	-3256	1	1	B	9220	-706	1090	1910	234	198		966	water	Brazeau-B. River
5W04716030200000	840223	34739	5	1	B	12200	-925	2170	2180	317	271		1190	oil+mud	Brazeau-B. River
5W04716020300000	830919	34784	4	1	B	13300	-948	2200	2200	407	356		1250	n/a	Brazeau-B. River
5W05614081000000	760418	35202	5	1	B	9370	-272	1190	1200	683	648		921	water	Brazeau-B. River
5W04616331200000	840403	35447	5	1	B	9520	-727	1980	2000	243	206		1260	n/a	Brazeau-B. River
5W04714181300000	860115	35468	3	1	B	12100	-822	2050	2050	415	364		1230	water+cond.+mud	Brazeau-B. River
5W04715080500000	850115	35480	1	1	B	12000	-795	2000	2010	426	381		1200	mud+cond.	Brazeau-B. River
5W04715140500000	860309	35488	1	1	B	10700	-715	1980	1980	372	334		1270	n/a	Brazeau-B. River
5W04715140700000	850216	35493	1	1	B	12100	-836	2090	2100	395	350		1260	oil+mud	Brazeau-B. River

Location	Date	Well ID	#	S	Q	p [kPa]	z [m]	dtop [m]	dbot [m]	H ₀	H ₁₀₀	H ₁₀₀₀	KB [m]	Fluid recovery	Aquifer
5W0662132100000	770731	35567	4	1	B	4350	229	483	493	672	655	714	714	water	Brazeau-B. River
5W0621917100000	700829	35601	2	1	B	8460	-89	974	989	763	730	876	876	water+mud+oil	Brazeau-B. River
5W06222011120000	850225	35615	2	1	B	8680	-132	967	975	753	719	841	841	water+mud	Brazeau-B. River
5W06420340700000	790119	35738	2	1	B	6540	2	760	779	668	643	765	765	n/a	Brazeau-B. River
5W06423170500000	791122	35743	5	1	B	7650	-118	934	938	663	632	818	818	water	Brazeau-B. River
5W05820231600000	671213	35781	1	1	B	10500	-303	1220	1260	766	726	913	913	water+oil	Brazeau-B. River
5W06122271100000	760120	35944	2	1	B	9370	-342	1180	1190	713	676	938	938	n/a	Brazeau-B. River
5W06118031000000	751210	36035	5	1	B	9170	-173	1090	1100	762	728	916	916	n/a	Brazeau-B. River
5W06324251100000	671231	36360	4	1	B	8130	-173	1000	1010	656	624	830	830	water+mud	Brazeau-B. River
5W06919150900000	800301	36536	6	1	B	3110	343	440	463	660	648	765	765	water+mud	Brazeau-B. River
5W05923040600020	571222	36812	5	1	B	12200	-468	1520	1540	774	728	1070	1070	water+cond.+mud	Brazeau-B. River
5W06220111200020	850709	36989	2	1	B	8410	-37	860	895	821	767	844	844	mud+cond.+water	Brazeau-B. River
6W06405271100000	781018	36930	5	1	B	9740	-333	1260	1270	660	622	928	928	water	Brazeau-B. River
6W06104201100000	790315	39044	5	1	B	10900	-560	1700	1730	550	508	1140	1140	n/a	Brazeau-B. River
6W06909050700020	770420	39157	13	1	B	4850	230	515	524	725	705	748	748	n/a	Brazeau-B. River
6W063034191100000	810503	39251	1	1	B	10300	-381	1390	1390	673	629	1010	1010	water+cond.+mud	Brazeau-B. River
6W06305201000000	790624	39276	1	1	B	10700	-385	1400	1430	699	654	1010	1010	water+mud	Brazeau-B. River
6W06711280900000	860223	51239	5	1	B	8300	-9	805	828	837	804	799	799	mud+cond.	Brazeau-B. River
5W05620350600000	870123	68655	2	1	B	11400	-363	1530	1540	803	754	1170	1170	water+mud	Brazeau-B. River
5W05518350200000	870117	68656	2	1	B	11700	-444	1510	1520	749	703	1070	1070	water+mud	Brazeau-B. River
5W05520080800000	860104	68666	1	1	B	13700	-582	1760	1800	806	751	1190	1190	water+mud	Brazeau-B. River
5W05520091400000	860304	68694	4	1	B	13500	-572	1790	1800	802	751	1220	1220	water+cond.	Brazeau-B. River
5W05527330900000	841121	68701	2	1	B	12000	-908	2150	2180	312	268	1240	1240	water+oil+mud	Brazeau-B. River
5W05517360700000	880222	76709	1	1	B	10800	-316	1220	1230	779	743	904	904	water+mud	Brazeau-B. River
5W06022240800020	871124	80708	1	1	B	10200	-281	1290	1310	775	739	1030	1030	water+mud	Brazeau-B. River
5W05819341100000	900224	80764	4	1	B	10700	-328	1230	1270	759	721	906	906	water+mud+oil	Brazeau-B. River
5W05622240900000	921019	83094	3	1	B	12100	-449	1340	1360	786	737	895	895	n/a	Brazeau-B. River
5W056921120700000	951023	-1596	1	1	C	11100	-349	1470	1500	781	730	1120	1120	water	Brazeau-B. River
5W04715291030000	950706	-2336	1	1	C	9420	-711	1900	1910	249	212	1190	1190	oil+mud	Brazeau-B. River
5W06326261300000	960319	-2907	3	1	C	8730	-213	1110	1120	677	643	903	903	water	Brazeau-B. River
5W04716030300000	840223	34739	4	1	C	13700	-959	2210	2220	442	384	1250	1250	n/a	Brazeau-B. River
5W05217091400000	820328	34795	4	1	C	10300	-486	1460	1470	564	524	963	963	mud	Brazeau-B. River
5W05318280600000	640902	34878	1	1	C	10900	-356	1320	1320	762	712	960	960	n/a	Brazeau-B. River
5W05625200700000	801215	34906	5	1	C	12400	-740	2030	2050	523	475	1290	1290	water+cond.	Brazeau-B. River
5W05719101030000	800319	34937	2	1	C	11000	-296	1470	1480	821	762	1180	1180	water+oil	Brazeau-B. River
5W05715071000000	800213	34983	1	1	C	10400	-275	1520	1520	787	744	1240	1240	water	Brazeau-B. River
5W04715210400000	850823	35192	1	1	C	12500	-860	2080	2100	398	345	1220	1220	oil+mud+cond.	Brazeau-B. River
5W05216361000000	760523	35304	2	1	C	11900	-540	1440	1450	674	626	903	903	n/a	Brazeau-B. River

Location	Date	Well ID	#	S	Q	p [kPa]	z [m]	dtop [m]	dbot [m]	H ₀	H ₁₀₀	M ₁₀₀	KB [m]	Fluid recovery	Aquifer
5W0561810130000	850226	35309	1	1	C	11100	-290	1410	1430	839	798	1110		n/a	Brazeau-B River
5W05611731070000	841130	35318	1	2	C	11100	-563	1520	1540	849	805	957		n/a	Brazeau-B River
5W0571904100000	851031	35346	1	1	C	11800	-366	1850	1860	816	771	1220		n/a	Brazeau-B River
5W0531715060000	830928	35424	1	1	C	12100	-492	1400	1430	745	694	912		water+cond.	Brazeau-B River
5W0521420160000	840108	35427	3	1	C	11000	-373	1350	1370	783	705	982		water+mud	Brazeau-B River
5W0471601120000	840907	35448	2	1	C	10700	-827	2050	2050	265	222	1220		mud	Brazeau-B River
5W0572301070000	850102	35462	1	1	C	12200	-555	1830	1840	694	641	1060		cond.+oil+water+mud	Brazeau-B River
5W0471513060000	850603	35469	1	1	C	10500	-727	1980	1990	346	302	1260		oil+cond.	Brazeau-B River
5W0502113070000	850726	35482	3	1	C	10500	-1010	2060	2060	60	19	1060		water	Brazeau-B River
5W0572214030000	841211	35485	1	1	C	12800	-524	1580	1590	783	731	1060		n/a	Brazeau-B River
5W0572214030000	841214	35485	2	1	C	12800	-552	1600	1620	780	703	1060		water+mud	Brazeau-B River
5W0471513100000	851030	35491	4	2	C	10100	-620	1870	1880	408	370	1250		mud	Brazeau-B River
5W0621917100000	700828	35601	1	1	C	9020	-128	1000	1020	791	756	876		oil	Brazeau-B River
5W0622011120000	850224	35615	1	1	C	8380	-121	960	968	733	700	841		water+mud	Brazeau-B River
5W0642024100000	630420	35626	7	1	C	6670	17	778	780	697	671	789		water	Brazeau-B River
5W0632510060000	780920	35674	9	1	C	8900	-245	1140	1140	663	627	892		water	Brazeau-B River
5W0651921060000	780814	35723	1	1	C	8130	158	830	838	681	681	790		water	Brazeau-B River
5W0622011100000	680814	35774	1	1	C	8810	-126	969	1000	517	663	667		water+mud+oil	Brazeau-B River
5W0621830500000	550413	35807	1	1	C	5320	209	654	671	781	730	877		water	Brazeau-B River
5W0622014040000	631219	35844	1	1	C	8480	-89	958	874	775	742	875		water+cond.+mud	Brazeau-B River
5W0622014040000	600113	35875	1	1	C	6710	62	810	830	746	720	891		water+mud	Brazeau-B River
5W0630208120000	640120	36970	4	1	C	10800	-440	1500	1520	683	619	1080		n/a	Brazeau-B River
5W0640502010000	570121	36980	2	2	C	9320	-300	1210	1230	650	614	928		n/a	Brazeau-B River
5W0640604160000	561028	36982	3	1	C	9910	-328	1170	1190	682	643	860		n/a	Brazeau-B River
5W0660301100000	770307	36985	5	1	C	5340	81	684	708	625	604	778		n/a	Brazeau-B River
5W0691303140000	810810	369234	1	1	C	6220	176	711	724	810	788	890		mud	Brazeau-B River
5W0632701060000	870118	50844	1	1	C	9720	-337	1360	1400	664	616	1070		water+mud	Brazeau-B River
5W0620415120000	860210	51228	2	1	C	9340	-284	1320	1330	658	621	1020		mud+water	Brazeau-B River
5W0491812110000	860402	69475	2	1	C	11800	-911	1900	1970	293	246	1050		mud+water+oil+cond.	Brazeau-B River
5W0552008080000	860101	69866	2	1	C	13700	-800	1790	1800	708	743	1190		water+mud+cond.	Brazeau-B River
5W0471419020000	861231	68676	1	1	C	11400	-716	1920	1920	450	401	1190		oil+mud	Brazeau-B River
5W0562321020000	900119	76720	2	1	C	14200	-073	1760	1800	779	719	1090		water+mud	Brazeau-B River
5W0521821080000	900108	76749	1	1	C	12100	-559	1470	1490	673	627	916		water+mud	Brazeau-B River
5W0691303110000	771207	80057	1	1	C	6260	-991	699	719	828	805	891		water+mud	Brazeau-B River
5W0552036130000	980225	-2854	1	1	A	22600	-891	2090	2120	1410	1324	1200		cond.	Cardium
5W0571723100000	760318	36369	7	1	A	10800	-586	1710	1710	491	453	1120		water	Cardium
5W0622530100000	771015	35584	6	1	A	13800	-608	1530	1550	768	715	929		water+mud	Cardium

Location	Date	Well ID	#	S	O	p [kPa]	z [m]	dtop [m]	dbot [m]	H ₀	H ₁₀₀	H ₁₀₀	KB [m]	Fluid recovery	Aquifer
5W0642307150000	680612	35814	4	1	A	8070	-419	1270	1280	403	372	856	Cardium	water	Cardium
5W0670432100000	680212	38894	1	1	A	10100	-276	963	978	755	714	693	Cardium	water+mud	Cardium
5W0670508100000	670206	38913	5	1	A	10700	-365	1140	1160	729	684	778	Cardium	water+mud	Cardium
5W0620526160000	660305	39334	1	1	A	19400	-818	1820	1830	1162	1084	1000	Cardium	oil+cond.	Cardium
5W0652701020000	660219	50887	1	1	A	11800	-436	1380	1440	763	721	947	Cardium	water+cond.+mud	Cardium
5W0641706140000	820613	34808	1	1	B	21200	-918	1930	1930	1239	1180	980	Cardium	oil+cond.+mud	Cardium
5W0631720090000	810316	34859	3	1	B	23300	-935	1890	1910	1439	1349	958	Cardium	n/a	Cardium
5W0651809120000	760702	35018	3	1	B	21100	-905	1920	1920	1243	1163	1010	Cardium	oil+cond.+mud	Cardium
5W0631822110000	721127	35166	1	1	B	23100	-1020	2010	2030	1337	1244	968	Cardium	oil	Cardium
5W0471527110000	721215	35248	1	1	B	26600	-1290	2450	2460	1424	1317	1170	Cardium	cond.+oil	Cardium
5W0471318130000	660114	35468	2	1	B	25800	-1290	2510	2530	1337	1239	1230	Cardium	n/a	Cardium
5W0642208070000	790219	35835	8	1	B	7920	-395	1220	1230	412	381	823	Cardium	n/a	Cardium
5W0642130110000	770120	36353	1	1	B	8630	-330	1140	1160	346	320	816	Cardium	mud+cond.+water	Cardium
5W0612516070000	760105	36359	1	1	B	14800	-758	1930	1910	732	673	1140	Cardium	water+mud	Cardium
5W0632429100000	670403	36361	3	1	B	12100	-485	1370	1390	743	701	888	Cardium	water+mud	Cardium
5W0642313110000	640314	36397	5	1	B	7670	-376	1340	1240	405	376	858	Cardium	water	Cardium
5W0632521100000	600404	36523	1	1	B	12300	-532	1390	1270	722	674	863	Cardium	water+cond.+mud	Cardium
5W0642318090000	800623	36528	1	1	B	8370	-408	1270	1290	447	414	861	Cardium	mud+cond.+water	Cardium
5W0632227040000	610114	36629	1	1	B	8200	-436	1270	1270	401	368	839	Cardium	water+cond.+mud	Cardium
5W0612636360000	810326	36758	5	1	B	14800	-727	1820	1840	794	724	1090	Cardium	water+mud	Cardium
5W0622503060000	820624	36827	4	1	B	9950	-555	1500	1500	460	420	944	Cardium	water+mud	Cardium
5W0670514110000	811207	36829	1	1	B	14100	-677	1760	1770	765	705	1080	Cardium	water+cond.	Cardium
5W0670733100000	790629	39082	1	1	B	10400	-337	1040	1060	724	682	709	Cardium	water	Cardium
5W0680316070000	800406	39085	1	1	B	10800	-338	1110	1110	765	721	757	Cardium	water+cond.	Cardium
5W0650222060000	810304	39184	3	1	B	9080	-185	860	905	737	702	700	Cardium	water	Cardium
5W0620417060000	830108	39212	7	1	B	11800	-453	1240	1270	750	704	789	Cardium	water+mud	Cardium
5W0620523060000	840628	39300	1	1	B	21300	-836	1900	1910	1331	1252	1070	Cardium	oil	Cardium
5W0620523060000	850628	39303	1	1	B	20000	-837	1800	1810	1199	1123	967	Cardium	n/a	Cardium
5W0491812110000	860321	68475	1	1	B	24100	-1380	2430	2440	1074	982	1050	Cardium	mud+cond.	Cardium
5W0501804100000	870728	68713	1	1	B	23400	-1310	2320	2330	1076	984	1010	Cardium	mud+cond.	Cardium
5W0672313060000	900310	80615	4	1	B	5310	-78	791	798	463	443	715	Cardium	n/a	Cardium
5W0581702060000	960831	-1223	1	1	C	10700	-563	1750	1760	529	486	1190	Cardium	water	Cardium
5W0471530070000	810927	34755	2	2	C	27900	-1320	2490	2490	1527	1415	1180	Cardium	mud+cond.	Cardium
5W0551819010000	810822	34841	1	1	C	19300	-888	1930	1940	1075	1004	1040	Cardium	oil+mud+cond.	Cardium
5W0531814060000	720918	34879	1	1	C	23100	-1030	2000	2030	1332	1234	975	Cardium	oil+cond.	Cardium
5W0541808130000	791230	34984	1	1	C	21900	-977	1950	1960	1253	1170	975	Cardium	cond.+mud+oil	Cardium
5W0541833130000	791118	34987	1	1	C	20000	-902	1870	1890	1135	1058	974	Cardium	mud+oil	Cardium
5W0571608100000	761024	35001	1	1	C	10700	-597	1660	1670	494	452	1070	Cardium	mud	Cardium

Location	Date	Well ID	#	S	Q	p [kPa]	z [m]	dtop [m]	dbot [m]	H ₀	H ₁₀₀₀	H ₁₀₀₀	KB [m]	Fluid recovery	Aquifer
5W0541812100000	690918	35003	2	1	C	22000	-900	1870	1910	1344	1258	969	Cardium	n/a	Cardium
5W0582102070000	760807	35010	2	1	C	21400	-835	1770	1800	1343	1263	942	Cardium	oil+cond.+mud	Cardium
5W0561928070000	760229	35047	1	1	C	21500	-807	2130	2160	1385	1300	1320	Cardium	oil+cond.+mud	Cardium
5W0561928060000	751213	35052	1	1	C	19000	-808	2160	2180	1124	1054	1350	Cardium	oil+cond.	Cardium
5W0531815100000	720115	35144	1	1	C	23300	-1030	1980	2010	1346	1254	961	Cardium	oil+cond.+mud	Cardium
5W0531819040000	630713	35160	1	1	C	22500	-924	1820	1840	1366	1281	896	Cardium	mud+oil	Cardium
5W0551935150000	790108	35308	1	1	C	20400	-871	1940	1980	1207	1129	1080	Cardium	mud+oil	Cardium
5W0602410110000	780102	35533	2	2	C	15100	-782	1830	1880	756	698	1050	Cardium	water+mud+cond.	Cardium
5W0592434040000	630412	35534	2	1	C	15400	-815	1950	1970	752	694	1130	Cardium	water+mud	Cardium
5W0632208020000	640304	35822	1	1	C	8730	-485	1340	1350	404	371	859	Cardium	mud+water	Cardium
5W0632509120000	580631	35653	1	1	C	13100	-579	1390	1410	753	705	833	Cardium	water+oil	Cardium
5W0581729080000	780121	35707	1	1	C	10600	-537	1800	1820	544	502	1070	Cardium	mud+water	Cardium
5W0642307150000	680611	35814	3	1	C	8280	-413	1270	1280	431	309	856	Cardium	mud+water	Cardium
5W0632120070000	781205	35815	2	1	C	7820	-418	1230	1230	380	346	808	Cardium	mud+water	Cardium
5W0612013100000	710308	35970	7	1	C	11600	-483	1400	1430	989	654	921	Cardium	water+mud	Cardium
5W0622105100000	770208	36348	2	1	C	8730	-529	1400	1420	361	327	878	Cardium	water+mud	Cardium
5W0632425110000	671231	36360	3	1	C	8870	-464	1290	1300	440	405	830	Cardium	mud	Cardium
5W0642609140000	570312	36362	1	1	C	12500	-502	1360	1380	773	723	852	Cardium	water+mud	Cardium
5W0642313110000	670313	36397	3	1	C	7600	-381	1240	1240	394	364	856	Cardium	mud	Cardium
5W0642506060000	800818	36546	1	2	C	12000	-487	1390	1410	738	689	897	Cardium	water+cond.+mud	Cardium
5W0622621100000	570112	36566	10	1	C	14300	-652	1600	1600	808	750	948	Cardium	water	Cardium
5W0591813060000	820817	36827	1	1	C	9910	-548	1490	1500	462	423	944	Cardium	water+mud	Cardium
5W0622735060000	811221	36834	8	1	C	13800	-660	1710	1720	742	693	1050	Cardium	water	Cardium
5W0632403060000	820120	36836	2	1	C	12800	-555	1430	1440	732	680	876	Cardium	water+cond.+mud	Cardium
5W0622227030000	840115	36906	1	1	C	8260	-495	1380	1400	347	315	883	Cardium	mud	Cardium
5W0591904120000	840303	36920	3	1	C	10000	-658	1520	1530	366	322	859	Cardium	mud	Cardium
5W0650523100000	781130	38860	1	1	C	13000	-620	1340	1380	802	754	820	Cardium	water+mud	Cardium
5W0684032910000	780301	38872	5	1	C	13000	-570	1440	1460	756	704	871	Cardium	n/a	Cardium
5W0660629100000	740404	38895	1	1	C	11500	-418	1240	1280	750	709	826	Cardium	mud+oil	Cardium
5W0680709100000	780402	39008	2	1	C	10100	-274	1000	1060	754	716	731	Cardium	water+mud	Cardium
5W0660407110000	790710	39021	2	1	C	11900	-467	1280	1280	744	699	798	Cardium	water	Cardium
5W0660413110000	800104	39026	1	1	C	11900	-457	1180	1210	752	709	732	Cardium	water+mud	Cardium
5W0681307100000	800229	39055	1	1	C	12000	-204	1170	1220	1015	972	966	Cardium	mud+water	Cardium
5W0630631060000	820326	39205	1	1	C	20900	-724	1730	1770	1407	1325	1010	Cardium	oil	Cardium
5W0660719150000	840802	39296	2	1	C	14500	-447	1270	1280	1029	974	834	Cardium	oil+mud	Cardium
5W0650622110000	850407	39329	3	1	C	13500	-560	1440	1450	820	763	880	Cardium	mud	Cardium
5W0690801160000	860824	51243	3	1	C	9460	-207	934	959	757	720	729	Cardium	n/a	Cardium
5W0582123130000	890402	63298	3	1	C	20600	-756	1720	1740	1345	1263	964	Cardium	n/a	Cardium

Location	Date	Well ID	#	S	Q	p [kPa]	z [m]	dtop [m]	dbot [m]	M ₀	M ₁₀₀	H ₁₀₀	KB [m]	Fluid recovery	Aquifer
6W0650434100000	891105	80086	2	2	C	12300	-482	1270	1340	771	724	796	796	water+mud+cond.	Cardium
6W0690321160000	950127	-3418	2	1	A	9710	-440	1090	1100	550	512	650	650	water	Dunvegan
5W0642317120000	830817	36850	2	1	A	7470	-682	1510	1520	79	50	820	820	mud+oil	Dunvegan
5W0672436110000	750325	35551	6	1	B	8870	-350	1120	1140	554	519	770	770	water+mud	Dunvegan
5W0672309110000	710721	35555	7	1	B	9330	-403	1170	1180	548	511	770	770	water	Dunvegan
5W0672421100000	710106	35598	1	1	B	9370	-403	1140	1180	552	515	750	750	mud+water	Dunvegan
5W0662304110000	710415	35956	7	1	B	10500	-617	1270	1280	557	512	760	760	water+mud+cond.	Dunvegan
5W0682325110000	711223	36243	1	1	B	7920	-258	975	1010	550	518	720	720	water+mud	Dunvegan
5W0682527020000	670715	36258	1	1	B	10600	-534	1250	1270	542	505	740	740	water	Dunvegan
5W0662120100000	760821	36281	1	1	B	7350	-416	1100	1120	333	304	700	700	water+mud	Dunvegan
5W0652123160000	850823	36998	4	1	B	6040	-477	1250	1260	138	115	780	780	water+mud+cond.	Dunvegan
6W0680109110000	721204	38966	1	1	B	10100	-480	1190	1200	552	510	710	710	water+mud	Dunvegan
6W0680123110000	671229	38990	1	1	B	10100	-468	1120	1150	560	522	680	680	water+mud	Dunvegan
6W0660501110000	780307	39009	2	1	B	12100	-917	1710	1720	316	269	790	790	n/a	Dunvegan
6W0680205070000	830323	39247	3	1	B	10700	-773	1610	1640	318	276	840	840	mud+cond.	Dunvegan
6W0630312100000	890308	80105	2	1	B	20800	-1100	2150	2160	1018	938	1100	1100	oil+mud+cond.	Dunvegan
5W0692218130020	871112	80602	3	1	B	7210	-190	909	919	545	517	720	720	mud	Dunvegan
5W0652113140000	920731	83084	3	1	B	6110	-483	1280	1290	139	116	790	790	water+mud	Dunvegan
5W0652122090000	920824	83085	1	1	B	6240	-485	1300	1320	141	117	800	800	water+mud	Dunvegan
6W0690327010000	980219	-539	2	1	C	9580	-467	1120	1130	510	472	860	860	water	Dunvegan
5W0662307070000	960922	-1563	2	1	C	10400	-512	1310	1350	552	507	800	800	mud	Dunvegan
5W0692212110000	811104	35506	2	1	C	7320	-196	847	861	550	521	650	650	water+mud	Dunvegan
5W06822431040000	810819	35523	1	1	C	10700	-873	1770	1780	221	176	900	900	mud+water+oil+cond.	Dunvegan
5W0642803020000	710225	35542	1	1	C	12800	-832	1770	1800	470	423	940	940	water+mud	Dunvegan
5W0672436110000	750324	35551	3	1	C	8930	-347	1120	1130	553	518	770	770	mud	Dunvegan
5W0672309110000	710720	35555	6	1	C	9140	-386	1150	1190	545	510	770	770	n/a	Dunvegan
5W0662132100000	770721	35567	1	1	C	7340	-386	1090	1100	362	333	710	710	water	Dunvegan
5W0622203100000	761010	35575	1	2	C	10500	-850	1730	1760	221	179	880	880	oil+mud	Dunvegan
5W0682115040000	641207	35617	2	1	C	7620	-424	1160	1170	353	323	740	740	mud	Dunvegan
5W0581609100000	770416	35693	7	1	C	11800	-730	1740	1790	468	427	1000	1000	mud+water	Dunvegan
5W0672106110000	790804	35792	5	1	C	7200	-369	1070	1070	366	337	700	700	mud+water	Dunvegan
5W0652405100000	621106	35853	2	1	C	11400	-653	1540	1560	505	464	900	900	water+mud	Dunvegan
5W0692619100000	730911	35957	2	1	C	7950	-310	988	1020	500	489	680	680	water+mud+cond.	Dunvegan
5W0662502110000	660223	36175	1	1	C	10800	-559	1360	1410	538	500	790	790	water+mud+cond.	Dunvegan
5W0692302100000	770707	36199	6	1	C	7810	-240	994	1000	557	526	760	760	water+mud	Dunvegan
5W0642521110000	731115	36332	1	1	C	12100	-728	1560	1590	501	458	840	840	water	Dunvegan
5W0662320700000	801202	36724	2	1	C	9830	-440	1210	1210	562	523	770	770	water+mud	Dunvegan
5W0642308090000	830127	36895	1	1	C	10100	-688	1490	1540	339	301	810	810	cond.+mud+oil	Dunvegan

Location	Date	Well ID	#	S	Q	p [kPa]	z [m]	dtop [m]	dbot [m]	H ₀	H ₁₀₀	H ₁₀₀₀	KB [m]	Fluid recovery	Aquifer
6W0680208110000	560127	38880	3	1	C	10600	-537	1240	1250	548	502		710	n/a	Dunvegan
6W0680215110000	760820	38901	1	1	C	10200	-484	1170	1200	553	516		890	n/a	Dunvegan
6W0680538100000	781003	38954	10	1	C	11000	-804	1590	1610	315	274		750	n/a	Dunvegan
6W0680228060000	770209	38989	6	1	C	10200	-501	1170	1180	540	499		670	n/a	Dunvegan
6W0680108060000	761215	38993	4	1	C	10100	-505	1220	1250	523	485		730	water+mud	Dunvegan
6W0680816060000	870211	51240	2	2	C	10200	-767	1450	1460	277	233		660	mud+cond.	Dunvegan
6W0680860210000	870312	63452	2	1	C	11700	-738	1440	1490	459	409		700	mud	Dunvegan
6W0680401060000	860217	80082	3	1	C	14300	-920	1750	1750	535	482		830	mud	Dunvegan
6W0680127070000	780204	80075	1	1	C	9820	-500	1200	1230	470	433		710	mud+water	Dunvegan
6W0680127070000	780205	80075	2	1	C	9740	-467	1150	1170	535	498		710	mud+cond.+water	Dunvegan
5W0672129070000	900322	80614	1	1	C	7500	-318	1020	1030	447	417		700	water+mud	Dunvegan
5W0672313060000	900310	80615	3	1	C	9170	-375	1090	1100	560	524		720	n/a	Dunvegan
5W0671513060000	961004	-1839	3	1	A	11900	-869	1930	1940	347	297		1060	water	Viking
5W0662116140000	960331	-3041	3	1	A	11800	-614	1340	1350	594	543		729	water	Viking
5W0651533150000	960115	-3279	1	1	A	11700	-806	1780	1800	382	341		979	water	Viking
5W0631435060000	81227	35606	1	1	A	8510	-482	1510	1520	386	352		1020	water+mud	Viking
5W0631419070000	740912	35788	1	1	A	9040	-521	1480	1490	400	365		953	water+mud	Viking
5W0651829110000	790225	35830	4	1	A	10600	-546	1400	1430	537	493		959	water	Viking
5W0591523100000	760324	35981	1	1	A	10800	-740	1660	1670	359	319		922	water+mud	Viking
5W0691829010000	741230	35911	3	1	A	6680	-264	1200	1210	417	391		939	water+mud	Viking
5W0662025100000	730226	35913	2	1	A	10200	-525	1320	1330	514	475		798	water+mud	Viking
5W0692819100000	730912	35957	3	1	A	9170	-544	1220	1250	391	355		679	water+mud	Viking
5W0611817060000	790811	36400	1	1	A	10900	-719	1600	1620	389	349		886	mud+water	Viking
5W0632028020000	601117	36569	3	1	A	9940	-797	1570	1590	206	167		787	water	Viking
5W0621521100000	760824	36807	4	1	A	9680	-804	1620	1640	381	343		1020	water+mud	Viking
5W0622503060000	811224	36829	5	1	A	15100	-1170	2260	2270	374	310		1090	n/a	Viking
5W0591406060000	820208	36980	2	1	A	11100	-768	1780	1810	367	320		1010	water+mud	Viking
5W0671533060020	830305	36999	1	1	A	7930	-397	1210	1220	411	380		916	water+mud	Viking
5W0641713160020	850121	36958	1	1	A	9090	-554	1490	1500	373	337		942	water+mud	Viking
5W0641501120000	850312	36967	1	1	A	8700	-506	1490	1500	381	347		969	water	Viking
6W0690705110000	780528	39032	6	1	A	14300	-1020	1740	1760	433	382		735	n/a	Viking
6W0660913070000	820118	39258	1	1	A	17900	-1410	2300	2310	416	344		869	n/a	Viking
5W0662120020000	851114	63282	1	1	A	11200	-622	1330	1330	518	476		709	oil+cond.	Viking
5W0652015040000	871207	80649	1	1	A	11500	-651	1400	1400	517	476		748	water+mud	Viking
5W0641722110000	920130	80668	3	1	A	9240	-554	1370	1380	366	352		819	water+mud	Viking
6W0671115080000	950124	-1851	3	1	B	18200	-1450	2350	2360	404	334		903	mud	Viking
5W0591503130000	950728	-2777	3	1	B	11500	-804	1810	1810	369	323		1010	water	Viking
5W0611516130000	961027	-2853	2	1	B	9880	-660	1550	1570	347	308		894	oil	Viking

Location	Date	Well ID	#	S	Q	p [kPa]	z [m]	dtop [m]	dbot [m]	H ₀	H ₁₀₀	H ₁₀₀₀	KB [m]	Fluid recovery	Aquifer
5W0611516130000	961027	-2853	2	2	B	9860	-660	1550	1570	345	306	894	894	oil	Viking
5W0611624140000	960815	-3084	2	1	B	10400	-890	1580	1590	374	329	891	891	water	Viking
5W0581511060000	761231	35055	5	1	B	11800	-835	1870	1990	371	322	1130	1130	water+mud	Viking
5W0581405100000	760131	35227	1	1	B	11800	-811	1850	1850	396	346	1040	1040	water	Viking
5W0652010100000	811118	35505	2	1	B	11300	-631	1380	1390	519	477	749	749	n/a	Viking
5W0642417100000	770811	35565	2	1	B	12800	-912	1790	1810	396	343	882	882	water	Viking
5W0682011140000	660304	35610	1	1	B	10800	-572	1330	1350	527	487	759	759	water+mud+oil	Viking
5W0661810040000	631008	35624	2	1	B	10400	-513	1310	1330	544	506	814	814	water	Viking
5W0631628120000	660116	35714	1	1	B	9710	-596	1540	1570	394	356	975	975	water+mud	Viking
5W0621625110000	781020	35852	4	1	B	9840	-620	1640	1660	383	344	1030	1030	water+mud	Viking
5W0662103120000	641230	35854	1	1	B	11200	-628	1430	1460	513	472	807	807	oil	Viking
5W0632019100000	790316	35869	2	1	B	11300	-802	1570	1590	350	306	767	767	water+mud	Viking
5W0611830070000	660331	36033	3	1	B	10100	-827	1780	1790	206	163	960	960	water	Viking
5W0631410100000	751024	36127	4	1	B	8960	-515	1460	1470	398	363	938	938	water+cond.+mud	Viking
5W0652231100000	700103	36148	3	1	B	11300	-697	1420	1450	451	411	732	732	water+cond.+mud	Viking
5W0652312070000	680818	36169	1	1	B	11700	-788	1540	1550	427	379	767	767	water+mud	Viking
5W0652422040000	640111	36184	2	1	B	11800	-783	1660	1670	423	374	880	880	water+cond.	Viking
5W0662335100000	806229	36206	1	1	B	10500	-635	1440	1450	440	394	812	812	water+mud	Viking
5W0662335100000	880628	36206	2	1	B	11000	-821	1430	1440	501	457	812	812	water+mud	Viking
5W0662527020000	670717	36258	2	1	B	12200	-739	1440	1480	509	457	736	736	water+mud	Viking
5W0662110040000	641112	36272	1	1	B	11600	-618	1400	1430	580	519	787	787	oil	Viking
5W0662109020000	650201	36275	2	1	B	11200	-619	1380	1410	527	479	764	764	oil	Viking
5W0671707060000	750204	36277	1	1	B	8330	-411	1260	1280	540	503	837	837	water+mud	Viking
5W0662123020000	650926	36280	1	1	B	10800	-579	1300	1310	537	489	724	724	water+mud	Viking
5W0621504060000	780911	36313	1	1	B	10000	-629	1550	1570	393	351	920	920	water	Viking
5W0642235070000	790126	36401	2	1	B	10700	-763	1620	1630	324	286	860	860	water	Viking
5W0621602110000	800308	36494	1	1	B	10200	-677	1650	1670	367	323	989	989	water+mud+oil	Viking
5W0662117100000	790816	36502	2	1	B	11600	-611	1320	1320	576	526	707	707	n/a	Viking
5W0652310110000	810509	36894	2	1	B	11900	-778	1560	1580	436	388	772	772	water+mud+cond.	Viking
5W0621904050000	840111	36907	2	2	B	8780	-841	1740	1750	55	21	904	904	mud	Viking
5W0591531080000	830307	36914	1	1	B	10800	-747	1650	1680	354	312	906	906	water+cond.	Viking
5W0641512160000	850123	36953	1	1	B	8980	-490	1470	1490	425	390	976	976	water+mud	Viking
5W0621428100000	841229	36991	1	1	B	8970	-552	1420	1430	363	327	869	869	water+cond.+mud	Viking
6W0660528100000	710117	38876	6	1	B	15100	-1140	1980	1980	400	340	839	839	water+mud	Viking
6W0660407110000	790721	39021	3	1	B	15000	-1140	1940	1960	386	330	798	798	water	Viking
6W0600123110000	800529	39099	1	1	B	18000	-1470	2760	2790	366	294	1290	1290	water+mud	Viking
6W0661027150000	800526	39190	2	1	B	19800	-1440	2460	2490	579	501	1010	1010	mud	Viking
6W0650222060000	830107	39212	5	1	B	14400	-1040	1830	1840	426	371	789	789	mud+water	Viking

Location	Date	Well ID	#	S	Q	p [kPa]	z [m]	dtop [m]	dbot [m]	H ₀	H ₁₀₀₀	H ₁₀₅₀	KB [m]	Fluid recovery	Aquifer
6W0680630100000	811017	39243	1	1	B	14000	-988	1690	1710	443	384		701	water+mud+cond.	Viking
5W0632321120000	860127	50842	3	1	B	9010	-954	1780	1800	-36	-71		832	mud+cond.	Viking
5W0652233010000	860317	50856	1	1	B	11400	-713	1430	1440	448	404		723	water+cond.+mud	Viking
5W06862117060000	871226	50862	1	1	B	10900	-628	1330	1330	483	440		703	n/a	Viking
6W0650324100000	870206	51237	1	1	B	14800	-1090	1840	1850	433	370		856	mud+water	Viking
5W0661817070000	890128	63301	1	1	B	10200	-493	1290	1300	549	507		799	water+cond.+mud	Viking
5W0642521100000	890202	63310	5	1	B	13200	-928	1770	1780	418	366		844	water+cond.+mud	Viking
6W0660414100000	880225	80065	2	1	B	14700	-1090	1810	1820	407	351		718	water+mud	Viking
6W0660415120000	891228	80066	4	1	B	14800	-1100	1810	1810	413	351		711	water+cond.+oil	Viking
5W0652113140000	920725	83084	2	1	B	11600	-665	1460	1460	517	472		794	water+mud	Viking
5W0652122080000	920703	83085	2	1	B	11600	-672	1470	1480	514	465		801	n/a	Viking
5W0612426130000	950129	-2806	2	1	C	14400	-1100	2130	2180	367	311		1030	water	Viking
5W0531929070000	741008	35094	2	1	C	20600	-1500	2500	2520	592	519		1000	oil+mud+cond.	Viking
5W0531929070000	741008	35094	2	2	C	20200	-1500	2500	2520	551	480		1000	oil+mud+cond.	Viking
5W0522013090000	760322	35200	2	2	C	29500	-1660	2690	2710	1346	1231		1030	mud	Viking
5W0642603020000	710402	35542	5	1	C	14600	-1030	1970	1970	457	401		942	water+cond.+oil	Viking
5W0662109100000	611020	35819	1	1	C	11700	-621	1350	1380	571	526		741	oil	Viking
5W0632510060000	780918	35674	4	1	C	14400	-1050	1940	1960	419	361		892	water+mud	Viking
5W0662028020000	690213	35701	2	1	C	10700	-550	1350	1360	542	499		801	cond.+oil+mud	Viking
5W0661908150000	790328	35742	2	1	C	10500	-538	1310	1320	528	491		774	water	Viking
5W0652134100000	780321	35753	3	1	C	11200	-630	1440	1450	507	468		812	water+mud	Viking
5W0621506070000	761102	35756	4	1	C	10200	-650	1610	1620	394	350		959	water	Viking
5W0621606020000	590118	35777	3	1	C	10500	-709	1600	1620	365	320		912	water+mud	Viking
5W0652004060000	631115	35787	1	1	C	9060	-542	1470	1480	381	346		928	water+mud	Viking
5W0622416070000	761107	35833	4	1	C	12000	-675	1440	1450	546	501		761	water	Viking
5W0692306060000	601011	35841	2	1	C	14200	-1090	2130	2150	357	302		1040	water+mud	Viking
5W0662214100000	680615	35859	1	1	C	9110	-488	1210	1220	441	405		728	water	Viking
5W0601421100000	770819	35927	1	1	C	11000	-632	1360	1380	493	446		734	water+oil	Viking
5W0682109040000	650621	35995	1	1	C	10400	-636	1500	1540	419	383		869	water+mud	Viking
5W0671803100000	641229	36002	1	1	C	11000	-624	1350	1350	493	454		724	n/a	Viking
5W0611803100000	751209	36035	3	1	C	9340	-450	1280	1280	502	465		822	water+mud	Viking
5W0632020110000	830809	36046	1	1	C	11300	-806	1570	1580	342	302		916	n/a	Viking
5W0662126100000	760204	36050	1	1	C	11100	-561	1300	1310	567	527		737	water+cond.	Viking
5W0662226070000	670712	36051	1	1	C	11100	-603	1320	1320	526	485		707	mud	Viking
5W0611924100000	670306	36066	1	1	C	10400	-846	1770	1780	214	173		936	water	Viking
5W0632008130000	761212	36102	4	1	C	11400	-823	1620	1650	341	294		796	water+mud	Viking
5W0632136060000	740211	36115	5	1	C	10800	-765	1580	1600	333	294		797	water+mud	Viking

Location	Date	Well ID	#	S	Q	p [kPa]	z [m]	dtop [m]	dbot [m]	H ₀	H ₁₀₀₀	H ₁₀₀₀	KB [m]	Fluid recovery	Aquifer
5W0652415040000	630524	36182	1	1	C	12100	-807	1680	1690	428	379	884	884	water+cond.	Viking
5W0662617120000	610113	36201	1	1	C	12400	-844	1630	1640	423	371	799	799	water+mud	Viking
5W0611725030000	771201	36239	4	1	C	10700	-723	1650	1650	368	326	924	924	water+mud	Viking
5W0662130100000	641206	36263	1	1	C	11200	-605	1250	1270	538	493	664	664	water+mud	Viking
5W0611536080000	800807	36471	4	1	C	9870	-616	1520	1530	390	351	915	915	water+mud	Viking
5W0652135100000	790925	36498	1	1	C	11400	-631	1390	1400	536	486	769	769	water+mud	Viking
5W0601633140000	800327	36535	2	1	C	10800	-731	1590	1620	369	328	865	865	mud+cond.+water	Viking
5W0612403100000	590113	36565	3	1	C	15300	-1210	2310	2340	347	290	1130	1130	water+mud	Viking
5W0622021110000	611123	36574	1	1	C	10200	-853	1690	1700	191	147	851	851	mud	Viking
5W0651917100000	590129	36657	1	1	C	11300	-615	1350	1360	532	493	743	743	water+mud	Viking
5W0621614100000	600301	36684	2	1	C	10200	-658	5300	5350	382	342	970	970	water	Viking
5W0611605060000	801020	36702	8	1	C	10900	-730	1580	1610	386	338	856	856	water+mud+oil	Viking
5W0652005100020	720723	36736	1	1	C	12100	-682	1430	1450	568	524	763	763	water	Viking
5W0662220040000	810224	36745	1	1	C	11000	-643	1400	1410	478	435	760	760	water+mud	Viking
5W0592035100000	810227	36746	4	1	C	10900	-1020	2020	2030	96	48	1000	1000	water+mud+cond.	Viking
5W0631527070000	810224	36747	4	1	C	8890	-523	1520	1530	383	348	998	998	water+cond.+mud	Viking
5W0662327060000	810601	36823	1	1	C	10700	-649	1450	1460	446	400	809	809	water+mud+cond.	Viking
5W0652123040000	810701	36868	1	1	C	11900	-664	1460	1470	551	502	794	794	mud	Viking
5W0651921100000	820213	36875	1	1	C	11200	-594	1380	1400	548	504	792	792	water+mud	Viking
5W0601403090000	821231	36909	3	1	C	10200	-667	1470	1470	374	333	787	787	water	Viking
5W0680421100000	661016	38862	1	1	C	12000	-854	1520	1550	373	322	669	669	water+mud	Viking
5W0680206110000	580315	38880	4	1	C	11900	-603	1500	1510	411	363	707	707	n/a	Viking
5W0670432100000	650224	38894	2	1	C	13100	-827	1620	1640	404	357	683	683	n/a	Viking
5W0650206060020	790207	38922	1	1	C	15800	-1140	1990	2030	468	409	856	856	water+mud	Viking
5W0660315060000	781018	38927	3	1	C	14200	-1030	1800	1840	425	362	768	768	water+mud	Viking
5W0660326100000	710214	38975	1	1	C	14800	-1110	1910	1930	402	341	794	794	water	Viking
5W0680709100000	780410	39008	6	1	C	15300	-1090	1820	1850	467	410	731	731	n/a	Viking
5W0681133070000	780304	39011	1	1	C	16800	-1310	2050	2060	397	337	746	746	n/a	Viking
5W0681133070000	780323	39011	5	1	C	16900	-1300	2040	2050	422	356	746	746	n/a	Viking
5W0670531070000	680126	39031	2	1	C	14100	-1020	1700	1720	419	362	685	685	water+mud	Viking
5W0681031100000	791009	39120	13	1	C	16800	-1230	1970	1980	479	417	743	743	water+mud	Viking
5W0680402060000	790808	39167	6	2	C	12700	-915	1610	1620	376	330	700	700	water+mud	Viking
5W0640210060000	810925	39217	2	1	C	16800	-1200	2090	2110	511	447	891	891	mud+water	Viking
5W0650232130000	840409	39281	3	1	C	13600	-1020	1860	1870	365	313	840	840	water+mud	Viking
5W0680518160000	850908	39338	1	1	C	12900	-958	1630	1640	358	308	675	675	water+cond.	Viking
5W0662112060000	851223	50861	3	1	C	11200	-599	1340	1340	547	499	740	740	mud	Viking
5W0662223060000	800627	63281	1	1	C	11200	-622	1360	1370	515	476	734	734	mud	Viking
5W0662120020000	851116	63282	4	1	C	11100	-606	1310	1320	530	482	709	709	oil+mud+water+cond.	Viking

Location	Date	Well ID	#	S	Q	P [kPa]	z [m]	dtop [m]	dbot [m]	H ₀	H ₁₀₄₀	H ₁₀₈₀	KB [m]	Fluid recovery	Aquifer
5W0681428030000	890313	63316	1	1	C	7000	-193	1070	1100	520	493		879	water+mud	Viking
6W0650434100000	891123	80086	6	1	C	15300	-1130	1920	1930	427	370		795	mud+water	Viking
5W0672313060000	900309	80815	1	1	C	9870	-572	1290	1300	444	405		715	water	Viking
5W0632404050000	900411	80655	2	1	C	13900	-1040	1910	1930	379	322		875	water+mud	Viking
5W0672634060000	960318	-1494	2	1	A	13600	-767	1490	1500	615	566		723	water	Upper Mannville
5W0682307070000	960923	-1563	3	1	A	13200	-758	1560	1580	592	536		803	water	Upper Mannville
5W0671115080000	950119	-1851	1	1	A	9890	-1540	2440	2470	-550	-590		803	mud	Upper Mannville
5W0682408110000	961007	-2441	5	1	A	12700	-702	1450	1470	591	543		750	water+mud	Upper Mannville
5W0681908150000	790327	35742	1	1	A	11000	-578	1350	1360	548	500		774	water	Upper Mannville
5W0662228100000	750727	35914	3	1	A	12300	-683	1400	1410	587	543		734	water+mud	Upper Mannville
5W0682005160000	720206	36163	3	1	A	11300	-577	1290	1310	578	531		711	water+mud	Upper Mannville
5W0681733100000	740112	36350	1	1	A	9210	-372	1280	1370	567	523		900	water+mud	Upper Mannville
5W0672135160000	790811	36470	3	1	A	11100	-565	1270	1280	569	523		705	water+mud	Upper Mannville
5W0662220040000	810226	36745	7	1	A	13300	-738	1500	1500	619	566		760	n/a	Upper Mannville
5W0612636060000	810304	36755	3	1	A	16100	-1250	2340	2380	391	328		1090	water+mud	Upper Mannville
5W0612624130000	801225	36776	1	1	A	16300	-1280	2440	2460	382	318		1160	water+cond.+mud	Upper Mannville
5W0642004120000	850306	36980	6	1	A	4840	-766	1570	1580	-272	-282		809	water	Upper Mannville
5W0680333100000	840120	39277	3	1	A	14200	-824	1500	1510	623	568		676	n/a	Upper Mannville
5W0680307060000	860605	39322	3	1	A	15600	-1000	1720	1720	585	529		719	n/a	Upper Mannville
5W0690502100000	850914	38331	7	1	A	16700	-982	1630	1640	715	655		658	water+cond.	Upper Mannville
5W0690704080000	860830	39335	6	1	A	18000	-1120	1840	1850	714	644		721	n/a	Upper Mannville
5W0690801160000	860823	51243	1	1	A	18300	-1140	1870	1900	722	654		729	water+mud	Upper Mannville
5W0671921070020	911111	80608	1	1	A	10300	-481	1250	1260	570	529		753	water+cond.	Upper Mannville
5W0671921070020	911113	80608	2	1	A	10700	-528	1290	1310	567	523		753	water+cond.	Upper Mannville
5W0641619070000	950121	-1633	2	1	B	9250	-564	1480	1490	379	343		917	water+mud	Upper Mannville
5W0641609080000	950312	-1805	1	1	B	9510	-572	1490	1500	397	360		922	water	Upper Mannville
5W0662018150000	830204	35513	2	1	B	11900	-666	1370	1400	544	500		706	water+cond.+mud	Upper Mannville
5W0662407070000	770227	35570	5	1	B	13600	-798	1640	1640	584	535		845	water+cond.+mud	Upper Mannville
5W0682407070000	770301	35570	6	1	B	14800	-837	1680	1690	670	614		845	n/a	Upper Mannville
5W0681902110000	741031	35586	3	1	B	10100	-452	1280	1290	573	538		840	water+mud	Upper Mannville
5W0672108110000	790803	35792	4	1	B	12000	-653	1350	1360	566	523		701	water+mud	Upper Mannville
5W0672314050000	790701	35793	7	1	B	12000	-644	1350	1350	575	532		709	water+mud	Upper Mannville
5W0682323110000	781012	35828	5	1	B	12900	-729	1520	1530	590	535		795	water+mud	Upper Mannville
5W0662529100000	730917	35946	1	1	B	14300	-795	1500	1510	661	607		707	water	Upper Mannville
5W0671914120000	730304	35948	2	1	B	10600	-510	1250	1260	575	529		752	water	Upper Mannville
5W0651824110000	750320	35979	4	1	B	11400	-579	1400	1410	584	538		822	water+mud	Upper Mannville
5W0671917030000	750106	36076	5	1	B	11000	-571	1310	1320	548	507		739	water	Upper Mannville
5W0621915100000	670515	36223	2	1	B	12900	-819	1680	1690	499	445		867	mud	Upper Mannville

Location	Date	Well ID	#	S	Q	p [kPa]	z [m]	dtop [m]	dbot [m]	H ₀	H ₁₀₄₀	H ₁₀₈₀	KB [m]	Fluid recovery	Aquifer
5W0581533070000	751214	36405	1	1	B	12000	-828	1780	1860	397	348	348	955	water+mud	Upper Mannville
5W0682136060000	790907	36439	2	1	B	10300	-476	1180	1200	574	534	534	708	water	Upper Mannville
5W0652130060000	770212	36803	1	1	B	12800	-728	1490	1510	578	527	527	762	water+mud+cond.	Upper Mannville
5W0642131110000	841121	36996	1	1	B	10800	-766	1570	1580	331	293	293	806	oil+water	Upper Mannville
6W0690803110000	781020	38868	4	1	B	18400	-1160	1890	1900	718	643	643	736	water+mud	Upper Mannville
6W0690710060000	770910	38881	4	1	B	17900	-1100	1800	1820	724	654	654	699	n/a	Upper Mannville
6W0680236110000	780221	38900	3	1	B	13800	-811	1480	1490	592	542	542	673	n/a	Upper Mannville
6W0671029110000	790228	38904	2	1	B	19700	-1470	2310	2330	535	461	461	840	water+mud	Upper Mannville
6W0690805110000	781211	38951	8	1	B	17700	-1160	1900	1910	646	575	575	734	water	Upper Mannville
6W0680526100000	710218	38975	3	1	B	12300	-1270	2060	2100	-18	-64	-64	794	n/a	Upper Mannville
6W0680226060000	770128	38989	1	1	B	14200	-1070	1520	1550	379	322	322	675	water	Upper Mannville
6W0690705110000	780604	39032	7	1	B	18300	-1130	1860	1870	730	664	664	675	n/a	Upper Mannville
6W0690724100000	800831	39061	6	1	B	14700	-1120	1800	1800	370	321	321	735	n/a	Upper Mannville
6W0670535130000	800109	39105	2	1	B	16600	-1130	1790	1790	560	497	497	676	water+cond.	Upper Mannville
6W0650435110000	810306	39181	1	1	B	19000	-1200	2020	2020	737	662	662	814	water+mud	Upper Mannville
6W0680333100000	840120	39277	2	1	B	14300	-875	1550	1560	586	527	527	676	n/a	Upper Mannville
6W0690512080000	841122	39294	4	1	B	15700	-954	1610	1620	646	585	585	658	n/a	Upper Mannville
6W0680518160000	850910	39338	3	1	B	15200	-1110	1790	1850	440	380	380	675	water+mud+cond.	Upper Mannville
6W0660402060000	890330	63463	3	1	B	18500	-1210	2010	2030	677	603	603	803	water+mud	Upper Mannville
6W0690609080000	850904	80049	1	1	B	17100	-1080	1820	1840	667	596	596	749	water+mud	Upper Mannville
5W06842132100000	780118	80639	1	1	B	11200	-754	1540	1560	388	344	344	791	water+mud+cond.	Upper Mannville
6W0680319100000	950915	-2265	1	1	C	15300	-958	1660	1680	606	542	542	709	water	Upper Mannville
5W0641934100300	960305	-3798	2	1	C	2960	-649	1400	1410	-348	-359	-359	751	mud	Upper Mannville
5W0542114110000	750418	35214	4	1	C	31600	-1620	2750	2760	1601	1477	1477	1120	mud	Upper Mannville
5W0652108060000	740126	35552	2	1	C	12100	-713	1490	1520	520	473	473	773	water+mud	Upper Mannville
5W0671407070000	740116	35585	5	1	C	8790	-328	1430	1460	568	534	534	1110	water	Upper Mannville
5W0662109100000	641024	35619	3	1	C	12100	-675	1390	1420	563	511	511	741	water	Upper Mannville
5W0581514070000	790103	35794	2	1	C	12200	-847	1970	2000	399	349	349	1140	water+cond.+mud	Upper Mannville
5W0632123100000	710226	36040	3	1	C	11600	-841	1630	1670	337	296	296	792	water+mud	Upper Mannville
5W0672301100000	641121	36160	3	1	C	12200	-850	1390	1400	593	548	548	752	water+mud	Upper Mannville
5W0622015120000	640703	36229	2	1	C	11500	-866	1730	1740	291	241	241	845	mud	Upper Mannville
5W0652120060000	780208	36304	3	1	C	12200	-687	1430	1760	554	509	509	748	water+mud+cond.+oil	Upper Mannville
5W0652005100000	680208	36318	1	1	C	12400	-718	1470	1490	549	497	497	763	mud+water	Upper Mannville
5W0622116100000	761023	36322	4	1	C	19000	-950	1790	1800	988	912	912	839	mud	Upper Mannville
5W0662603160000	580901	36351	1	1	C	14700	-830	1600	1680	668	611	611	774	water	Upper Mannville
5W0671827010000	791226	36476	1	1	C	9860	-442	1220	1230	563	524	524	793	water+mud	Upper Mannville
5W0662331160000	800331	36499	5	1	C	12700	-701	1490	1500	594	544	544	790	water	Upper Mannville

Location	Date	Well ID	#	S	Q	p [kPa]	z [m]	dtop [m]	dbot [m]	H ₀	H _{100p}	H ₁₀₈₀	KB [m]	Fluid recovery	Aquifer
5W0622131060000	711028	36701	4	1	C	12700	-930	1790	1800	361	315	884	884	n/a	Upper Mannville
5W0632301060000	810407	36752	1	1	C	12700	-967	1820	1840	331	278	850	850	water+mud	Upper Mannville
5W0652613070000	810206	36814	4	1	C	16500	-1010	1810	1830	675	607	810	810	n/a	Upper Mannville
5W0621831130000	810418	36845	5	1	C	8070	-747	1560	1580	76	44	812	812	mud+cond.	Upper Mannville
5W0662522050000	830827	36848	3	2	C	14700	-797	1570	1580	697	644	770	770	water	Upper Mannville
5W0632004080000	811023	36863	3	1	C	11500	-851	1640	1650	325	276	797	797	mud+water	Upper Mannville
5W0652123040000	810702	36868	2	1	C	13000	-717	1510	1520	508	557	794	794	n/a	Upper Mannville
6W0680615060000	821216	38852	4	1	C	15400	-1070	1750	1760	503	439	682	682	water	Upper Mannville
6W0680215110000	760824	38901	2	1	C	14400	-871	1560	1570	598	540	693	693	n/a	Upper Mannville
6W0682063107000	790113	38950	4	2	C	38900	-1770	2950	2970	2192	2043	1180	1180	cond.+water+mud	Upper Mannville
6W0680826110000	780424	39007	3	1	C	18400	-1170	1980	2010	703	633	801	801	n/a	Upper Mannville
6W0680734060000	580725	39121	1	1	C	14400	-1090	1790	1800	376	321	698	698	mud+cond.	Upper Mannville
6W0680734060000	580724	39121	5	1	C	14300	-1200	1790	1800	262	202	698	698	n/a	Upper Mannville
6W0680333100000	840119	39277	1	1	C	14700	-897	1570	1590	605	544	676	676	n/a	Upper Mannville
5W0622235100000	881215	63295	4	1	C	10700	-930*	1820	1830	163	119	874	874	water+mud	Upper Mannville
5W0681212020000	891202	63467	2	1	C	10900	-1610	2380	2410	-502	-542	768	768	mud+cond.	Upper Mannville
5W0642303110000	880112	80640	1	1	C	12200	-905	1750	1760	342	291	842	842	mud+water	Upper Mannville
5W0631730120000	960129	-2746	4	1	A	14500	-930	1750	1750	545	491	821	821	oil	Lower Mannville
5W0682117130000	960806	-2857	1	1	A	13700	-758	1420	1430	635	585	664	664	water	Lower Mannville
5W0661625140000	770323	35568	3	1	A	12400	-669	1530	1540	594	546	866	866	water+mud	Lower Mannville
5W0682404100000	750301	35584	1	1	A	14600	-873	1630	1640	615	558	760	760	water+mud	Lower Mannville
5W0662522020000	730915	35590	1	1	A	16500	-1040	1770	1800	638	577	735	735	water+mud	Lower Mannville
5W0681928110000	721130	35595	1	1	A	12600	-653	1450	1480	636	582	796	796	water+cond.	Lower Mannville
5W0652128020000	640718	35621	3	1	A	15400	-943	1700	1710	629	568	765	765	water	Lower Mannville
5W0661810040000	631012	35624	4	1	A	13700	-764	1580	1580	634	579	814	814	water+mud	Lower Mannville
5W0642024100000	630414	35626	4	1	A	15700	-992	1770	1780	608	547	789	789	water+mud+oil+cond.	Lower Mannville
5W0682416060000	601219	35630	2	1	A	15200	-972	1700	1710	574	518	735	735	water+mud	Lower Mannville
5W0651724060000	790329	35698	3	1	A	13500	-793	1740	1750	582	530	950	950	water+cond.	Lower Mannville
5W0631407070000	631118	35787	2	1	A	13700	-764	1690	1710	634	579	928	928	water+mud	Lower Mannville
5W0651829110000	790222	35830	2	1	A	14200	-803	1660	1680	643	589	859	859	water+mud	Lower Mannville
5W0652004060000	761109	35833	5	1	A	14900	-962	1720	1730	556	498	761	761	oil+mud	Lower Mannville
5W0692513060000	761008	35862	1	1	A	14200	-836	1570	1590	613	556	758	758	water+mud+oil	Lower Mannville
5W0691706100000	711207	35939	1	1	A	11500	-589	1510	1520	581	538	923	923	water	Lower Mannville
5W0651816160000	700220	35985	2	1	A	14000	-824	1660	1710	603	548	839	839	water	Lower Mannville
5W0661625080000	660128	35990	1	1	A	12300	-625	1490	1500	630	581	875	875	water+mud	Lower Mannville
5W0611922120000	650111	36065	4	1	A	15700	-1150	2060	2070	453	389	920	920	water	Lower Mannville
5W0631415110000	750218	36130	3	1	A	13000	-754	1720	1740	571	520	967	967	n/a	Lower Mannville
5W0631415070000	770108	36138	1	1	A	12500	-757	1720	1740	521	468	966	966	oil	Lower Mannville

Location	Date	Well ID	#	S	Q	p [kPa]	z [m]	dtop [m]	dbot [m]	H ₀	H ₁₀₀₀	H ₁₀₀₀	KB [m]	Fluid recovery	Aquifer
5W0642014100000	640804	36145	2	1	A	16000	-975	1790	1800	654	593	822	822	water+mud	Lower Mannville
5W0662617120000	610122	36201	3	1	A	18300	-1290	2070	2090	577	504	799	799	water+mud	Lower Mannville
5W0631414060000	760319	36214	1	1	A	13000	-749	1700	1710	574	525	952	952	n/a	Lower Mannville
5W0682204070000	680426	36237	1	1	A	14200	-858	1530	1540	591	534	679	679	water+mud	Lower Mannville
5W0682325110000	711230	36243	4	1	A	13800	-782	1510	1520	621	571	725	725	water+mud	Lower Mannville
5W0621809100000	760909	36328	3	1	A	14400	-1030	1870	1890	441	381	839	839	oil	Lower Mannville
5W0661612160000	730121	36741	3	A1	A	12400	-699	1580	1610	565	516	881	881	n/a	Lower Mannville
5W0631820060000	810325	36750	3	1	A	14300	-975	1750	1760	479	427	775	775	n/a	Lower Mannville
5W0682303605000	830308	36917	1	1	A	12900	-711	1480	1490	604	553	755	755	water+cond.+mud	Lower Mannville
5W0671406070000	840302	36945	1	1	A	11400	-548	1630	1650	613	569	1090	1090	water+mud	Lower Mannville
5W0651529090000	840313	36946	1	1	A	12700	-663	1610	1640	634	582	945	945	water+mud	Lower Mannville
5W0680421100000	661230	38862	7	1	A	18900	-1340	2010	2020	584	513	669	669	water	Lower Mannville
5W0690412120000	830117	39275	1	1	A	17900	-1260	1910	1920	569	494	658	658	water+mud+cond.	Lower Mannville
5W0682204090000	860108	50872	1	1	A	14100	-807	1480	1490	628	575	679	679	n/a	Lower Mannville
5W0682634160000	820507	63268	2	1	A	15700	-1030	1710	1710	569	509	682	682	water+mud+cond.	Lower Mannville
5W0641916150000	880222	63276	1	1	A	14600	-984	1740	1750	507	447	758	758	mud+oil	Lower Mannville
5W0632133100000	890303	63307	2	1	A	15700	-1120	1890	1900	477	419	770	770	water+mud	Lower Mannville
5W0640218160000	890120	63464	1	1	A	19400	-1530	2400	2420	449	372	874	874	mud+cond.	Lower Mannville
5W0660414110000	880226	80065	3	1	A	20800	-1540	2270	2290	573	499	718	718	n/a	Lower Mannville
5W0630213120020	880220	80104	5	1	A	22800	-1690	2690	2700	617	525	990	990	water+mud+oil+cond.	Lower Mannville
5W0651602020000	951111	-586	2	1	B	13100	-711	1740	1750	626	573	1030	1030	water	Lower Mannville
5W0631717040000	950305	-957	2	1	B	15600	-934	1900	1910	653	595	966	966	mud+oil	Lower Mannville
5W0471529100000	950712	-2338	2	1	B	39600	-1870	3050	3070	2172	2011	1190	1190	water	Lower Mannville
5W0690411140000	950209	-3019	2	1	B	19200	-1090	2040	2060	873	792	961	961	oil+mud	Lower Mannville
5W0571629100000	610407	34938	6	1	B	16500	-1190	2260	2270	498	427	1080	1080	oil	Lower Mannville
5W0661633040000	840302	35520	2	1	B	12300	-626	1480	1510	629	580	853	853	water+mud+cond.	Lower Mannville
5W0672217060000	740225	35553	2	1	B	14500	-829	1620	1630	577	522	701	701	water+cond.+mud	Lower Mannville
5W067231060000	680318	35558	5	1	B	15300	-976	1730	1750	586	524	701	701	water+cond.+mud	Lower Mannville
5W0622530100000	771010	35564	3	1	B	21200	-1540	2460	2470	619	538	757	757	water+cond.	Lower Mannville
5W0621813100000	751026	35581	5	1	B	14100	-987	1860	1870	448	395	929	929	n/a	Lower Mannville
5W0671407070000	750116	35585	3	1	B	11700	-558	1660	1690	530	589	876	876	water	Lower Mannville
5W0661818100000	720312	35597	4	1	B	13400	-787	1600	1620	581	526	1110	1110	n/a	Lower Mannville
5W0672436100000	601231	35629	2	1	B	14600	-868	1630	1640	625	563	772	772	water+cond.+mud+oil	Lower Mannville
5W0672436100000	610103	35629	4	1	B	15100	-965	1730	1740	569	515	772	772	water+mud	Lower Mannville
5W0661926100000	590307	35634	2	1	B	13600	-793	1570	1590	598	540	775	775	water	Lower Mannville
5W0652423100000	630912	35733	3	1	B	17400	-1190	2040	2050	587	515	864	864	water+mud+cond.	Lower Mannville
5W0621811100000	660321	35744	2	1	B	14500	-1020	1920	1930	456	401	908	908	mud	Lower Mannville

Location	Date	Well ID	#	S	Q	p [kPa]	z [m]	dtop [m]	dbot [m]	H ₀	H ₁₀₄₀	H ₁₀₉₀	KB [m]	Fluid recovery	Aquifer
5W0641718120000	611212	35758	1	1	B	14600	-852	1650	1670	840	579		805	water+mud	Lower Mannville
5W0672329060000	611222	35766	2	1	B	15500	-986	1750	1760	595	533		778	water+cond.	Lower Mannville
5W0672329060000	611229	35766	3	1	B	15600	-998	1770	1780	593	531		778	water	Lower Mannville
5W0641927020000	600308	35770	1	1	B	14900	-898	1640	1660	618	562		745	water+mud	Lower Mannville
5W0672108110000	790802	35792	3	1	B	14100	-850	1550	1560	592	532		701	water+cond.+mud	Lower Mannville
5W0692114090000	751127	35799	5	1	B	12700	-678	1380	1390	617	567		709	mud	Lower Mannville
5W0662025100000	730225	35913	1	1	B	14100	-821	1620	1620	613	561		798	water+mud	Lower Mannville
5W0632202020000	830220	35972	1	1	B	18200	-1280	2140	2150	578	504		871	water+mud	Lower Mannville
5W0681919160000	620210	35998	1	1	B	13000	-720	1480	1480	608	554		759	water	Lower Mannville
5W0622725070000	701114	36043	3	1	B	21400	-1590	2650	2660	585	508		1050	water+mud+cond.	Lower Mannville
5W0641828020000	600202	36099	7	1	B	14600	-864	1630	1630	627	567		769	water+mud	Lower Mannville
5W0632136060000	740210	36115	2	1	B	14900	-1080	1870	1880	436	380		797	n/a	Lower Mannville
5W0631515020000	691118	36159	5	1	B	13500	-805	1740	1740	572	518		940	water+mud	Lower Mannville
5W0611725030000	771205	36239	6	1	B	14700	-984	1910	1910	517	457		924	water+mud	Lower Mannville
5W0682232070000	720605	36242	1	1	B	13600	-753	1420	1470	630	580		701	water+mud	Lower Mannville
5W0682023070000	710127	36289	1	1	B	12900	-702	1470	1470	612	562		768	water+cond.+mud	Lower Mannville
5W0682111060000	730103	36292	1	1	B	13800	-803	1490	1500	601	550		698	water+mud+cond.+oil	Lower Mannville
5W0622508030000	780702	36305	3	1	B	23300	-1470	2440	2460	900	814		967	n/a	Lower Mannville
5W0631718060000	690122	36324	1	1	B	14300	-936	1820	1830	521	466		881	water	Lower Mannville
5W0632430100000	770501	36346	3	1	B	19500	-1390	2270	2280	586	521		881	water+mud	Lower Mannville
5W0642130100000	770306	36353	3	1	B	15900	-1010	1830	1850	609	548		816	water+cond.+mud	Lower Mannville
5W0672332110000	771107	36373	6	1	B	15400	-968	1750	1750	598	541		782	n/a	Lower Mannville
5W0672332110000	771107	36373	7	1	B	14900	-927	1710	1710	591	533		782	n/a	Lower Mannville
5W0662211000000	780211	36380	2	1	B	15300	-930	1660	1670	634	570		734	water+mud	Lower Mannville
5W0692519070020	760329	36382	1	1	B	15000	-934	1700	1720	592	536		773	water	Lower Mannville
5W0661411120000	590126	36392	1	1	B	12000	-568	1730	1750	659	608		1160	water+mud	Lower Mannville
5W0652234110000	731212	36402	1	1	B	15800	-1030	1750	1780	575	519		722	water+mud	Lower Mannville
5W0581531110000	791208	36463	3	1	B	15400	-1060	2090	2130	517	449		1030	cond.+water+oil+mud	Lower Mannville
5W0652033100000	790128	36554	6	1	B	14900	-912	1650	1680	602	548		742	water+mud	Lower Mannville
5W0662402100000	620721	36619	1	1	B	17200	-1160	2040	2060	598	526		897	water+mud	Lower Mannville
5W0641731100000	620308	36623	4	1	B	14100	-803	1620	1630	634	579		820	water+cond.+mud	Lower Mannville
5W0632270400000	610128	36629	5	1	B	18200	-1270	2090	2110	585	514		839	water+mud	Lower Mannville
5W0642326060000	590302	36685	5	1	B	17500	-1200	2100	2110	587	515		912	water+mud	Lower Mannville
5W0602703130000	801127	36698	2	1	B	25000	-1910	3200	3200	633	540		1270	n/a	Lower Mannville
5W0651911040000	600813	36733	5	1	B	14500	-864	1660	1660	615	557		794	mud+water	Lower Mannville
5W0651929070000	780402	36734	1	1	B	14600	-843	1620	1650	645	588		786	water+mud	Lower Mannville
5W0671901020000	600119	36740	2	1	B	13500	-776	1520	1540	603	547		753	water+cond.	Lower Mannville
5W0612636060000	810303	36758	2	1	B	20100	-1610	2700	2720	440	360		1090	water+mud	Lower Mannville

Location	Date	Well ID	#	S	Q	p [kPa]	z [m]	dtop [m]	dbot [m]	H ₀	H ₁₀₀₀	H ₁₀₄₀	KB [m]	Fluid recovery	Aquifer
5W0682610050000	810204	36763	1	1	B	15700	-977	1660	1680	623	562	688	688	water+mud	Lower Mannville
5W0622735060000	811217	36834	4	1	B	21100	-1610	2860	2710	537	458	1050	1050	water+mud	Lower Mannville
5W0641835070000	811129	36869	2	1	B	13600	-825	1590	1610	559	508	771	771	water+cond.+mud	Lower Mannville
5W0641823050000	811105	36870	3	1	B	14800	-868	1640	1660	641	583	789	789	water+mud	Lower Mannville
5W0622032040000	840205	36901	3	1	B	10500	-1130	1960	1970	-59	-101	822	822	water+mud+cond.	Lower Mannville
5W0651611130000	840320	36943	3	1	B	13100	-742	1790	1790	595	542	1050	1050	oil+water+cond.	Lower Mannville
5W0651611130000	840321	36943	4	1	B	13200	-704	1750	1780	638	590	1050	1050	water+mud	Lower Mannville
5W0672314010S00	840310	36944	4	1	B	14500	-868	1580	1600	615	553	717	717	water+cond.+mud	Lower Mannville
5W0672208160000	841003	36962	5	1	B	14600	-908	1620	1630	584	523	718	718	water+mud	Lower Mannville
5W0631801150000	850215	36978	3	1	B	14200	-956	1850	1860	495	436	894	894	water+mud	Lower Mannville
5W0641818060000	841201	36997	4	1	B	15100	-954	1730	1740	588	526	777	777	water+cond.+mud	Lower Mannville
5W0631919120000	850927	37001	3	1	B	15700	-1000	1780	1790	597	539	781	781	mud+water	Lower Mannville
6W0680421100000	670101	38862	8	1	B	19100	-1330	2010	2020	611	542	669	669	water	Lower Mannville
6W0680215110000	760829	38901	4	1	B	17000	-1100	1790	1800	629	566	693	693	n/a	Lower Mannville
6W0680215110000	760902	38901	6	1	B	17600	-1210	1900	1910	583	515	693	693	n/a	Lower Mannville
6W0630324070000	781130	38903	4	1	B	21400	-1720	2640	2750	460	378	914	914	water+oil	Lower Mannville
6W0630324070000	781201	38903	5	1	B	22200	-1700	2610	2620	568	476	914	914	mud+water	Lower Mannville
6W0620308060000	790402	38947	4	1	B	25700	-1920	2950	2970	704	599	1040	1040	n/a	Lower Mannville
6W0680108060000	761214	38993	3	1	B	17700	-1200	1940	1940	602	535	734	734	n/a	Lower Mannville
6W0670531070000	680327	39031	5	1	B	22000	-1370	2050	2070	870	786	685	685	water+mud	Lower Mannville
6W0650535100000	791221	39104	5	1	B	25100	-1690	2460	2480	869	770	778	778	water+cond.+mud	Lower Mannville
6W0680311110000	590814	39116	3	1	B	18400	-1270	1980	1990	605	533	714	714	water	Lower Mannville
6W0650211070000	811119	39225	2	1	B	20600	-1480	2340	2350	621	539	867	867	water+cond.+mud	Lower Mannville
6W0610513060000	840216	39285	3	1	B	27500	-2170	3200	3270	641	525	1040	1040	water+cond.+mud	Lower Mannville
6W0680411160000	840713	39290	4	1	B	18600	-1370	2050	2060	532	453	691	691	water+mud	Lower Mannville
5W0622122110000	860313	50826	4	1	B	16500	-1210	2100	2110	468	407	877	877	mud+cond.	Lower Mannville
5W0631927080000	880209	50839	1	2	B	12300	-1000	1790	1820	258	206	800	800	n/a	Lower Mannville
5W0641936120000	870128	50850	4	1	B	14900	-870	1630	1650	645	590	763	763	water	Lower Mannville
5W0662223060000	800628	63281	3	1	B	14900	-962	1700	1710	559	498	734	734	water+mud+cond.	Lower Mannville
5W0632133100000	890304	63307	3	1	B	15600	-1120	1890	1900	475	409	770	770	water+mud+cond.	Lower Mannville
5W0660402060000	890329	63463	2	1	B	21300	-1620	2420	2430	553	468	803	803	water+mud	Lower Mannville
5W0551534070000	861220	68707	1	1	B	16600	-1240	2160	2170	452	387	921	921	oil+water+cond.	Lower Mannville
6W0650325100000	891104	80081	1	1	B	21100	-1410	2230	2250	746	658	822	822	mud+cond.	Lower Mannville
6W0650328100000	900623	80082	2	1	B	21300	-1560	2400	2420	605	528	846	846	mud+water	Lower Mannville
5W0642136110000	831123	36904	1	1	A	16200	-1110	1880	1890	537	478	778	778	water+mud	Nordegg
5W0621420140000	840317	36939	4	1	A	14500	-893	1800	1800	587	528	896	896	oil+water+cond.	Nordegg
5W0561930110000	810824	34793	5	1	A	22300	-1610	2950	2960	671	576	1350	1350	water+mud	Nordegg
5W0572317100000	710625	35402	3	1	A	26300	-1940	2990	3010	740	638	1050	1050	water	Nordegg

Location	Date	Well ID	#	S	Q	p [kPa]	z [m]	dtot [m]	dbot [m]	H ₀	H ₁₀₄₀	H ₁₀₉₀	KB [m]	Fluid recovery	Aquifer
5W0572114060000	770406	34902	10	1	B	22400	-1690	2660	2690	590	506	405	963	water+mud+cond.	Nordeg
5W0651411100000	820923	36882	2	1	B	12300	-694	1870	1880	562	512	458	1180	water	Nordeg
5W0692205030000	910915	80601	5	1	B	14500	-894	1590	1610	585	527	462	696	water+mud+oil	Nordeg
5W0561610120000	671107	35138	1	1	B	19200	-1340	2240	2270	612	542	456	903	water+mud	Nordeg
5W0662009050000	880111	80630	1	1	B	15100	-934	1660	1680	600	546	478	736	water+mud	Nordeg
5W0661612040000	821222	36820	4	1	B	13200	-717	1640	1660	624	577	517	927	water+mud+oil	Nordeg
5W0511609110000	650324	35039	5	1	B	24700	-1820	2910	2930	692	601	490	1110	mud	Nordeg
5W0561704060000	910617	76718	2	1	B	20700	-1440	2450	2470	674	589	496	1010	mud+cond.	Nordeg
5W0581932110020	890206	63313	2	1	B	20800	-1440	2290	2300	680	599	505	845	water	Nordeg
5W0572011100000	770419	34900	3	1	B	22600	-1600	2900	2930	703	615	514	1300	water	Nordeg
5W0531526110000	781101	35239	2	1	B	21400	-1420	2330	2350	769	678	581	916	water	Nordeg
5W0491836060000	660404	35165	2	1	C	27800	-2100	3140	3150	560	625	500	1040	water	Nordeg
5W0641805050000	570720	36626	7	1	C	16000	-1080	1880	1890	550	488	416	793	water+oil	Nordeg
5W0631818020000	591214	36330	6	1	C	15700	-1030	1820	1840	576	509	438	799	water+mud	Nordeg
5W0661611020000	620326	36618	4	1	C	12700	-735	1660	1680	562	510	453	916	water+mud+cond.	Nordeg
5W0691915090000	800229	36536	4	2	C	12100	-671	1450	1480	559	515	461	785	water+mud	Nordeg
5W059150710004	960331	-441	4	1	C	17100	-1130	2140	2160	607	546	469	1010	water	Nordeg
5W0552223050000	671011	34901	3	1	C	26100	-1990	3010	3040	674	568	451	1030	water+cond.+mud	Nordeg
5W0532008100000	630216	35350	2	1	A	27168	-2089.7	3130	3190	680	573	451	1040	water+gas	Triassic
5W0541834060000	850929	35498	3	1	A	22712	-1655.9	2610	2620	659	570	468	960	n/a	Triassic
5W0551705060000	760425	35370	5	1	A	21808	-1580.4	2520	2530	643	557	459	946	water	Triassic
5W0551826060000	811113	68678	3	1	A	22124	-1562.0	2620	2640	693	607	507	1050	n/a	Triassic
5W0551833100000	760112	35348	6	1	A	22349	-1598.1	2690	2690	680	592	492	1090	n/a	Triassic
5W0561715090000	950910	-1113	1	1	A	20890	-1458.1	2460	2460	671	589	496	1000	oil+water	Triassic
5W0571715090000	950618	-2044	1	1	A	19765	-1364.1	2500	2510	650	573	484	1140	water	Triassic
5W0571722070000	960317	-1649	1	1	A	19629	-1353.2	2500	2510	648	571	482	1140	water	Triassic
5W0572102100000	761024	34899	2	1	A	23848	-1762.0	2930	2940	669	575	468	1170	water+gas+mud	Triassic
5W0572314110000	951104	-2487	2	1	A	25354	-1936.0	3010	3030	649	549	435	1080	water	Triassic
5W0601620120000	630923	35936	2	1	A	16637	-1117.4	1930	1940	579	513	439	816	water+mud	Triassic
5W0601623060000	701005	35876	1	1	A	16652	-1083.9	1900	1920	614	548	473	822	water	Triassic
5W0602224070000	960324	-1659	1	1	A	21484	-1516.3	2540	2550	674	589	493	1030	oil	Triassic
5W0621715070000	720302	36029	1	1	A	17190	-1079.6	1970	1970	673	605	528	891	water+mud	Triassic
5W0631627110000	731216	80678	1	1	A	15582	-922.3	1950	1980	666	605	535	1030	water	Triassic
5W0631628120000	660124	35714	4	1	A	15126	-950.4	1910	1930	592	532	464	975	water+mud	Triassic
5W0641602090000	830317	36885	7	1	A	16076	-902.7	1890	1900	736	673	601	989	n/a	Triassic
5W0641604100000	661001	36106	4	1	A	14789	-921.4	1830	1840	586	528	462	921	water+mud+gas	Triassic
5W0641635100000	660110	36370	5	1	A	13734	-836.7	1800	1810	563	510	448	968	water	Triassic
5W0641735100000	790313	35739	5	1	A	14368	-894.6	1740	1760	570	514	449	846	water+mud+gas	Triassic

Location	Date	Well ID	#	S	Q	p [kPa]	z [m]	dtop [m]	dbot [m]	H ₀	H ₁₀₀₀	H ₁₀₀₀	KB [m]	Fluid recovery	Aquifer
5W0662014100000	960118	-2231	3	1	A	15511	-958.8	1740	1740	622	561	492	781	water+mud	Triassic
5W0671821110000	960123	-2521	1	1	A	13720	-811.8	1580	1590	587	533	471	769	water	Triassic
5W0671924140000	740205	35702	4	1	A	13953	-817.2	1580	1620	605	550	488	768	water+mud	Triassic
5W0672006040000	840119	36925	2	1	A	15547	-963.9	1730	1760	621	560	490	766	water+oil+gas	Triassic
5W0672101060000	860228	50868	1	1	A	15700	-959.6	1720	1780	641	579	509	770	water+mud	Triassic
5W0672125060000	890220	63304	1	1	A	15111	-917.5	1650	1660	623	564	496	736	water+oil+mud+gas	Triassic
5W0672135160000	790811	36470	2	1	A	14858	-904.6	1610	1620	610	552	485	705	water+mud	Triassic
5W0672212140000	651229	35611	1	1	A	16048	-997.9	1660	1670	638	575	503	664	water+mud+oil	Triassic
5W0672436100020	850630	37009	2	1	A	15938	-1068.6	1830	1850	548	494	422	772	n/a	Triassic
5W0682210120000	860908	35646	4	1	A	14943	-942.8	1610	1620	580	522	455	673	water+mud+oil	Triassic
5W0682210120000	661017	35646	1	1	A	14708	-934.8	1610	1630	564	507	441	673	water+oil+mud+gas	Triassic
5W0682223030020	630812	36813	1	1	A	14842	-915.0	1570	1570	598	540	473	658	water+mud+gas+oil	Triassic
5W0682230150000	951231	-3263	3	1	A	14600	-927.5	1650	1660	561	504	438	727	water+mud	Triassic
5W0682325110000	720103	36243	6	1	A	15261	-949.8	1670	1690	606	546	477	725	water+mud+oil+gas	Triassic
6W0680423010000	840710	39286	1	1	A	19423	-1456.4	2180	2190	524	447	360	728	oil+mud	Triassic
6W0690321160000	950128	-3418	3	1	A	17897	-1266.3	1920	1920	558	488	407	652	water+mud	Triassic
5W0522104070000	750313	35035	5	1	B	29243	-2328.1	3430	3450	653	538	407	1100	n/a	Triassic
5W0561821100000	840413	35440	2	1	B	21570	-1539.9	2720	2740	659	574	477	1190	n/a	Triassic
5W0562114100000	800623	34869	2	1	B	24787	-1862.9	2920	2940	664	567	455	1060	water+gas+mud	Triassic
5W0562218070000	740330	35109	2	1	B	27300	-2010.2	3200	3240	793	666	543	1190	water+gas	Triassic
5W0562220060000	750327	35060	1	1	B	26190	-1984.9	3160	3160	669	582	464	1180	water	Triassic
5W0562413130000	801223	34905	2	1	B	27931	-2132.7	3270	3280	714	605	479	1140	water+gas	Triassic
5W0571715090000	950620	-2044	2	1	B	19751	-1363.1	2500	2510	651	573	484	1140	water+mud	Triassic
5W0571805110000	770705	35286	1	1	B	21202	-1525.2	2720	2720	636	553	458	1190	water+mud+gas	Triassic
5W0581905100000	650106	35103	5	1	B	21808	-1573.4	2620	2630	650	564	466	1050	water+mud	Triassic
5W0582227110000	720709	36338	2	1	B	23671	-1758.4	2760	2770	655	562	455	999	n/a	Triassic
5W0592123060000	760317	35908	1	1	B	22781	-1548.7	2590	2620	774	684	582	1050	n/a	Triassic
5W0601635090000	610422	36579	1	1	B	16224	-1050.0	1810	1840	604	540	487	764	water	Triassic
5W0611603010000	730314	36024	2	1	B	16411	-1050.0	1860	1890	623	558	485	816	water+mud	Triassic
5W0612118110000	761106	35574	1	1	B	19414	-1446.9	2430	2440	532	456	389	990	water+gas	Triassic
5W0632128110000	720111	36333	1	1	B	17238	-1232.9	2020	2030	524	457	379	794	water+mud+gas+oil	Triassic
5W0642135060000	740102	35804	1	1	B	16238	-1133.9	1900	1900	521	458	385	767	water+mud+oil+gas	Triassic
5W0642326060000	590308	36685	6	1	B	19442	-1373.4	2270	2290	608	532	445	912	water+mud+gas	Triassic
5W0652201070000	730308	35803	6	1	B	16417	-1156.7	1840	1960	517	452	379	787	water+gas+mud	Triassic
5W0652325110000	761102	35929	2	1	B	17919	-1172.0	1920	1940	655	584	504	748	water+mud	Triassic
5W0652334100000	721020	35746	7	1	B	17767	-1161.3	1900	1940	650	580	500	742	water+mud+oil	Triassic
5W0662014100000	960117	-2231	1	1	B	15817	-1022.8	1800	1810	590	528	456	781	oil	Triassic
5W0662123020000	651005	36280	3	1	B	15957	-1000.1	1720	1730	627	564	492	724	water	Triassic

Location	Date	Well ID	#	S	Q	p [kPa]	z [m]	dtop [m]	dbot [m]	H ₀	H ₁₀₀₀	KB [m]	Fluid recovery	Aquifer
5W0662135080000	850314	36969	3	1	B	15636	-961.9	1730	1740	632	571	500	n/a	Triassic
5W0671822140000	810227	36767	1	1	B	13978	-816.5	1600	1630	608	554	491	water+mud	Triassic
5W0671908080000	710411	36314	1	1	B	14738	-881.8	1640	1650	621	563	496	water	Triassic
5W0671914120000	730305	35948	4	1	B	14260	-845.2	1600	1620	608	553	488	water	Triassic
5W0671921070000	721121	35945	5	1	B	14527	-899.8	1650	1670	581	524	459	n/a	Triassic
5W0671924160000	960128	-3439	3	1	B	14035	-825.5	1600	1600	605	550	487	water+mud	Triassic
5W0672018100000	711222	35731	4	1	B	15236	-922.6	1710	1720	630	571	502	mud+water	Triassic
5W0672018100020	870724	63292	1	1	B	15195	-930.9	1710	1720	618	558	490	water+mud+gas+oil	Triassic
5W0672021100000	880307	80612	3	1	B	15670	-968.4	1710	1720	629	567	497	water+mud+oil	Triassic
5W0672202110000	740331	36042	1	1	B	16179	-1027.8	1730	1740	621	558	485	water+oil	Triassic
5W0672208160000	841001	36962	3	1	B	16471	-1090.0	1810	1810	589	524	450	n/a	Triassic
5W0672330080000	841124	37004	1	1	B	16632	-1071.7	1840	1860	624	559	484	n/a	Triassic
5W0681829120000	700318	36295	1	1	B	13155	-764.1	1640	1680	577	525	466	water+mud	Triassic
5W0681919160000	620212	35998	2	1	B	13821	-813.2	1570	1570	596	541	479	water+gas	Triassic
5W0682126070000	740316	36285	1	1	B	14611	-862.6	1570	1580	627	570	504	water+gas+oil+mud	Triassic
5W0682136060000	790909	36439	4	1	B	14161	-844.1	1550	1550	599	544	480	water+gas+oil+mud	Triassic
5W0682203160000	840626	50871	1	1	B	14803	-940.8	1620	1640	568	510	444	water+oil	Triassic
5W0682223030020	630814	36813	2	1	B	14822	-907.1	1560	1570	604	546	479	water+mud	Triassic
5W0682232070000	720608	36242	3	1	B	14927	-909.5	1610	1620	612	554	486	water+oil+mud+gas	Triassic
5W0682234110000	580911	35801	2	1	B	14988	-894.3	1570	1570	634	575	507	water+mud+gas+oil	Triassic
5W0682404100000	750309	35584	3	1	B	17554	-1177.1	1940	1940	612	543	465	oil+mud	Triassic
5W0692012160000	950323	-3354	1	1	B	13201	-765.0	1490	1500	581	529	470	n/a	Triassic
6W0650325100000	891115	80081	2	1	B	21141	-1661.8	2480	2490	493	410	315	mud+gas	Triassic
6W0680108060000	761213	38993	2	1	B	17640	-1303.6	2040	2050	495	425	346	water+mud	Triassic
6W0680436020000	850707	39327	2	1	B	19220	-1401.0	2060	2070	558	483	397	water+gas+mud	Triassic
6W0690109070000	701226	39197	1	1	B	16374	-1182.6	1840	1890	486	422	349	water+mud	Triassic
6W0690122070000	720313	38997	1	1	B	16070	-1163.4	1820	1860	475	412	339	water+gas+mud	Triassic
6W0690327010000	960218	-539	1	1	B	17760	-1252.3	1910	1910	558	489	409	water	Triassic
5W0491910150000	720413	34837	1	1	C	30480	-2375.9	3500	3510	731	612	475	mud	Triassic
5W0522104070000	750303	35035	1	1	C	29978	-2322.9	3400	3420	733	615	481	water+mud	Triassic
5W0522133100000	760214	35013	15	1	C	28593	-2249.1	3300	3390	666	553	425	water+mud	Triassic
5W0532031040000	771211	35076	6	1	C	27390	-2100.7	3150	3180	691	584	461	water	Triassic
5W0541911070000	820906	34781	2	1	C	24564	-1805.1	2790	2810	699	603	492	water+mud+gas	Triassic
5W0542211070000	741007	35143	1	1	C	27852	-2128.0	3200	3310	691	582	458	water	Triassic
5W0542229070000	800328	34985	1	2	C	27204	-2140.1	3160	3180	633	528	404	water	Triassic
5W0542305160000	810807	34805	4	1	C	31126	-2418.3	3600	3630	755	633	493	mud+water+gas	Triassic
5W0551729150000	540809	34923	15	1	C	22036	-1530.7	2570	2590	716	629	530	water	Triassic
5W0552132040000	690825	35292	1	1	C	26310	-1996.7	3070	3080	685	592	464	water+gas+mud	Triassic

Location	Date	Well ID	#	S	Q	p [kPa]	z [m]	dhop [m]	dbot [m]	H ₀	H ₁₀₄₀	H ₁₀₈₀	KB [m]	Fluid recovery	Aquifer
5W0562132100000	740315	35059	1	2	C	24242	-1821.5	2790	2800	650	555	446	963	water	Triassic
5W0562220060000	750404	35060	3	1	C	26001	-1981.5	3160	3180	685	567	450	1180	water	Triassic
5W0571630110000	950207	-2579	1	1	C	19087	-1306.7	2380	2390	639	564	478	1080	water	Triassic
5W0572011110000	770330	34900	2	1	C	22839	-1638.9	2940	2950	689	600	497	1300	mud	Triassic
5W0581928110000	591229	35708	2	1	C	21078	-1501.8	2460	2470	647	564	469	966	water	Triassic
5W0582206060000	810203	80757	2	1	C	24279	-1832.3	2860	2860	643	547	438	1030	water	Triassic
5W0591506140000	781210	36406	4	1	C	17321	-1136.8	2150	2170	629	561	483	1020	water+mud+oil	Triassic
5W0602111100000	780310	35791	4	1	C	21552	-1532.2	2530	2530	665	580	483	996	n/a	Triassic
5W0611509040000	721215	36422	4	1	C	16105	-1017.1	1830	1850	625	561	489	817	water	Triassic
5W0611820060000	570107	36656	3	1	C	18521	-1239.0	2210	2220	649	576	493	980	water+mud	Triassic
5W0621506070000	781031	35756	3	1	C	15700	-985.4	1940	1970	615	553	483	959	water+oil	Triassic
5W0631610100000	961003	-2201	1	1	C	15710	-962.3	2000	2010	639	578	507	1040	mud+water	Triassic
5W0631818100000	680311	36110	1	1	C	15326	-974.5	2020	2020	588	528	459	1050	water+oil+mud	Triassic
5W0612030100000	631020	36335	1	1	C	18171	-1354.8	2230	2240	497	426	345	877	water+mud	Triassic
5W0612225070000	770219	35750	3	1	C	19181	-1429.2	2390	2400	526	451	365	964	water+mud+gas	Triassic
5W0622102120000	631005	36233	1	1	C	17958	-1336.2	2210	2260	494	424	343	880	water+mud	Triassic
5W0651836080000	641228	36198	1	1	C	14575	-906.5	1770	1800	579	522	457	888	water+mud+oil	Triassic
5W0652033100000	781220	36554	2	1	C	16146	-1074.2	1820	1830	572	508	436	742	water+oil+mud	Triassic
5W0652234110000	731217	36402	2	1	C	17236	-1121.7	1840	1860	635	568	490	722	water+gas	Triassic
5W0661905040000	720719	35912	1	1	C	15476	-954.0	1720	1730	624	563	493	765	water+mud	Triassic
5W0662123020000	651001	36280	2	2	C	15892	-1005.8	1730	1750	614	552	480	724	water+mud	Triassic
5W0662536060000	810321	36762	2	1	C	16925	-1196.7	1940	1960	529	462	386	748	water+oil+gas	Triassic
5W0671803100020	871230	80606	2	1	C	14142	-838.7	1660	1670	603	547	484	823	mud	Triassic
5W0671819090000	930727	83059	1	1	C	14209	-828.2	1600	1610	620	565	501	773	water+mud	Triassic
5W0672019070000	820121	35502	3	1	C	14952	-919.4	1690	1700	605	546	479	773	water+mud+oil	Triassic
5W06722108110020	911201	80613	2	1	C	16064	-1005.5	1700	1710	632	569	497	703	mud	Triassic
5W0672329060000	841215	35766	6	1	C	17359	-1156.1	1930	1930	613	545	467	778	water+gas+mud	Triassic
5W0672330060000	811228	37004	6	1	C	17735	-1167.6	1940	1950	640	571	491	775	mud+water+oil	Triassic
5W0672435060000	750426	35582	2	1	C	17103	-1173.2	1940	1960	570	503	426	768	water+mud+oil	Triassic
5W0672435060000	750528	35582	3	1	C	16681	-1086.6	1850	1860	614	548	473	768	water+oil	Triassic
5W0681809070000	830227	36913	1	1	C	13450	-763.6	1570	1600	607	555	494	811	water+gas+mud	Triassic
5W0681916110000	700212	36294	1	1	C	13780	-818.7	1590	1640	586	532	470	782	water+oil+mud	Triassic
5W0681928110000	721204	35595	2	1	C	13608	-788.8	1580	1600	598	545	484	796	water+oil+gas	Triassic
5W0681928110000	721228	35595	8	1	C	13744	-779.1	1570	1590	622	568	506	796	water+gas+oil	Triassic
5W0681934100000	750214	35583	3	1	C	13273	-759.3	1580	1600	594	542	482	815	water+mud	Triassic
5W0682021000000	740310	36299	1	1	C	14062	-843.1	1580	1590	590	535	472	750	water+mud	Triassic
5W0682136060000	790903	36439	1	1	C	14420	-848.3	1550	1560	622	565	500	708	water+mud+oil	Triassic
5W0682224070000	590603	36593	3	1	C	14881	-901.6	1550	1560	615	557	490	648	water	Triassic

Location	Date	Well ID	#	S	Q	p [kPa]	z [m]	dtop [m]	dbot [m]	H ₀	H ₁₀₀₀	H ₁₀₉₀	KB [m]	Fluid recovery	Aquifer
5W0682224070000	580603	36593	2	1	C	15101	-897.9	1550	1550	641	582	514	648	n/a	Triassic
5W0682224090000	570606	35809	1	2	C	15152	-906.8	1540	1550	638	578	510	645	oil	Triassic
5W0682315060000	650303	36287	2	1	C	16077	-1013.8	1770	1790	625	562	490	761	water+mud	Triassic
5W0682403070000	831221	36937	3	1	C	16221	-1045.8	1810	1830	608	544	471	749	water+oil+mud	Triassic
5W0682403120000	900316	80594	1	1	C	17402	-1168.7	1910	1920	605	537	459	737	water+mud+oil	Triassic
5W0682203050000	591008	36279	1	1	C	14785	-892.8	1560	1570	614	556	490	677	oil+water	Triassic
5W0692203070000	591130	36207	1	2	C	14570	-884.5	1560	1560	601	544	478	673	water+oil+gas+mud	Triassic
5W0692503070000	721210	36381	3	1	C	17282	-1175.0	1890	1900	587	519	441	707	water+gas	Triassic
6W0670318140000	850411	39320	1	1	C	20731	-1541.6	2350	2380	572	490	397	809	water+gas+mud	Triassic
6W0670426040000	840912	39287	2	1	C	21085	-1574.2	2300	2310	575	492	398	730	water+gas	Triassic
6W0680123110000	680111	39990	2	1	C	17087	-1231.7	1920	1930	510	443	366	680	water+mud+gas+oil	Triassic
6W0680307060000	860605	39322	1	1	C	19659	-1469.4	2190	2190	535	458	369	719	mud+water+oil+gas	Triassic
6W0690403100000	850122	39313	3	2	C	19412	-1410.0	2070	2080	568	493	405	666	water+mud+gas	Triassic
6W0690608080000	840830	39289	4	1	C	22645	-1601.1	2290	2300	707	618	517	689	gas+water+oil+mud	Triassic
6W0690724100000	800830	39061	5	1	C	21982	-1597.7	2270	2290	643	557	458	676	water+gas	Triassic
6W0680618060000	831013	39356	1	1	C	28086	-1723.8	2430	2430	1139	1029	903	704	oil	Triassic
6W0680630050000	810123	39179	5	1	C	31085	-1694.8	2400	2430	1474	1352	1212	706	oil	Triassic
6W0680619100000	790309	38948	2	1	C	32325	-1701.0	2400	2410	1594	1467	1322	695	oil	Triassic
6W06806031100000	830909	39235	1	1	C	34103	-1657.3	2360	2370	1819	1685	1532	703	oil	Triassic
5W0692118040000	840918	36942	2	1	A	14800	-936	1580	1590	569	515	448	647	water	Permian
5W0672124100000	660328	35810	2	1	A	15800	-1020	1750	1770	591	529	458	742	water+oil+mud	Permian
5W0672018100000	711221	35731	3	1	A	15700	-1010	1790	1830	591	529	458	786	water	Permian
5W0611916030020	920703	83075	1	1	A	19600	-1320	2230	2230	683	601	513	914	-	Permian
6W0650921110000	701223	38935	2	1	A	34600	-2740	3810	3850	791	651	496	1080	-	Permian
5W0672007110000	731208	36028	4	1	B	15500	-1010	1780	1800	569	509	440	763	water + mud + oil	Permian
5W0682403120000	900317	80594	2	1	B	18000	-1240	1980	1980	594	524	443	737	-	Permian
5W0672102100000	660222	36376	3	1	B	16200	-1070	1810	1820	588	518	445	748	water + oil + cond.	Permian
5W0652604100000	630123	36372	1	1	B	22000	-1620	2530	2540	823	536	437	915	water+mud	Permian
5W0632227040000	610201	36629	6	1	B	19900	-1410	2240	2250	616	541	451	839	water + mud + oil + cond.	Permian
5W0692513060000	761015	35862	2	1	B	17300	-1160	1910	1930	605	536	458	758	water+oil+mud	Permian
5W0591535040000	610303	36319	1	1	B	16700	-1100	1960	1990	604	537	462	886	-	Permian
5W0672309110000	710719	35555	4	1	B	18100	-1230	1960	2000	613	544	463	767	water + oil + mud + cond.	Permian
5W0631504100000	630102	36162	1	1	B	14800	-913	1900	1910	598	538	471	990	water+mud	Permian
5W0672218060000	700120	35602	2	1	B	17100	-1130	1850	1860	609	546	469	719	water	Permian
5W0642328040000	840401	36940	1	1	B	19800	-1400	2190	2210	623	541	452	793	water+mud	Permian
5W0632323030000	850725	37000	2	1	B	20100	-1420	2240	2250	633	550	460	828	water+mud	Permian

Location	Date	Well ID	#	S	Q	p [kPa]	z [m]	dtop [m]	dbot [m]	H ₀	H ₁₀₄₀	H ₁₀₈₀	KB [m]	Fluid recovery	Aquifer
5W0652613070000	810204	36814	1	1	B	21500	-1550	2360	2370	644	557	461	810	water+mud	Permian
5W0521628100000	620914	34885	6	1	B	22900	-1680	2600	2630	652	565	462	944	water	Permian
6W0660436060000	680320	38864	4	1	B	25100	-1900	2650	2700	663	560	447	753	-	Permian
5W0521520040020	650127	34839	3	1	B	22700	-1630	2540	2550	678	595	493	921	water+mud	Permian
5W0631522040000	630322	35096	2	1	B	21400	-1500	2420	2450	684	598	501	927	water + mud + cond.	Permian
6W0680530090000	810303	39183	2	1	C	24870	-1837	2510	2530	675	698	489	927	water+mud+gas	Permian
5W0672314010S00	840308	36944	2	1	C	16900	-1140	1860	1880	577	516	440	717	water + oil + cond. + mud	Permian
5W0672202020000	651205	36519	6	1	C	16700	-1140	1830	1830	569	497	422	693	water + mud + oil	Permian
5W0672314010S00	840306	36944	1	1	C	16800	-1140	1860	1870	563	507	431	717	-	Permian
5W0672221060000	850717	50869	1	2	C	16600	-1110	1800	1810	583	517	442	699	water+mud	Permian
5W0662603160000	580915	36351	3	1	C	21000	-1520	2290	2300	612	538	444	774	water + oil	Permian
5W0691829010000	741230	35911	2	1	C	12600	-714	1650	1660	572	521	464	939	water+mud	Permian
5W0631410110000	691021	36368	3	2	C	14000	-844	1780	1790	579	528	465	935	water + cond. + oil	Permian
5W0662331160000	800330	36499	4	1	C	18000	-1230	2020	2030	602	534	453	790	water + cond. + oil + mud	Permian
5W0682203160000	840717	50871	3	1	C	16300	-1060	1720	1730	596	538	464	669	water + mud + oil	Permian
5W0672421100000	710120	35598	3	1	C	18300	-1260	2000	2010	606	534	451	751	water + mud + oil	Permian
5W0662309100000	761013	35745	3	1	C	18300	-1260	2040	2050	609	534	451	779	water+mud	Permian
5W0631502060000	891119	80677	1	1	C	14700	-907	1830	1840	593	534	468	928	water + cond.	Permian
5W0631515100000	650131	35784	3	1	C	14800	-892	1830	1840	595	539	473	946	water + mud + cond.	Permian
5W0652421130000	820305	36867	1	1	C	19700	-1390	2280	2280	620	541	452	885	mud + water + cond.	Permian
5W0671917030000	750105	36076	2	1	C	15200	-945	1680	1690	602	545	477	739	water+mud	Permian
6W0660207090000	790704	38905	1	1	C	24000	-1800	2580	2650	644	552	444	785	water + mud + cond.	Permian
5W0571610070000	770909	35000	4	1	C	19100	-1320	2370	2380	623	552	466	1050	water + cond. + mud + oil	Permian
5W0662617120000	610201	36201	5	1	C	21500	-1550	2350	2350	635	557	461	799	water + mud + oil	Permian
5W0531634040000	661101	35272	2	1	C	21500	-1560	2450	2460	637	547	451	899	water	Permian
5W0641713160000	720326	36374	3	1	C	15000	-926	1870	1880	607	544	477	941	water	Permian
5W0641607060000	720407	36211	1	1	C	15200	-940	1810	1820	611	550	482	875	water+mud	Permian
5W0632002020000	701212	36336	2	1	C	18500	-1260	2070	2090	628	553	470	818	mud + oil + water	Permian
5W0631611150000	701224	36044	1	1	C	15400	-949	1960	1970	625	560	491	1010	-	Permian
6W0680206100000	560305	38880	10	1	C	22700	-1650	2350	2360	670	575	473	707	water	Permian
6W0650201120000	621124	38985	5	1	C	24900	-1860	2700	2710	688	581	469	852	-	Permian
6W0670705070000	770801	38883	1	1	C	30700	-2310	3150	3170	823	699	561	840	-	Permian
5W0671503110000	810117	36771	1	1	A	12100	-676	1620	1640	552	510	456	940	cond. + oil + mud + water	Mississippian
5W0641828020000	600209	36099	10	1	A	15800	-1030	1790	1800	576	519	448	769	water	Mississippian

Location	Date	Well ID	#	S	Q	p [kPa]	z [m]	dtop [m]	dbot [m]	H ₀	H ₁₀₀₀	H ₁₀₅₀	KB [m]	Fluid recovery	Aquifer
5W0652111010000	751109	35579	3	1	A	17400	-1190	1960	1970	584	515	437	769	water + mud + cond. + oil	Mississippian
5W0671615060000	880219	80605	2	1	A	12400	-708	1700	1710	561	507	452	997	-	Mississippian
5W0671827010000	791227	36476	2	1	A	13800	-834	1620	1620	568	519	457	783	water	Mississippian
5W0661509100000	780723	35762	3	1	A	12500	-715	1760	1770	564	510	454	1050	water + cond. + mud	Mississippian
5W0671826100000	740107	36799	1	1	A	13800	-834	1640	1650	570	519	457	810	water+mud	Mississippian
5W0671803100020	871229	80606	1	1	A	14300	-884	1700	1720	573	518	453	823	water+mud	Mississippian
5W0671503060000	690125	35729	1	1	A	12300	-685	1620	1630	564	521	465	939	water + cond. + oil + mud	Mississippian
5W0671511100000	710315	36008	1	1	A	11800	-644	1740	1760	563	513	460	1100	water+mud	Mississippian
5W0661928100000	800408	36496	4	1	A	15100	-959	1760	1770	580	521	453	806	water+mud	Mississippian
5W0661510050000	701221	35918	1	1	A	12600	-715	1740	1750	569	520	463	1030	water + mud + cond.	Mississippian
5W0642020060000	641121	36180	4	1	A	17800	-1220	2030	2040	595	525	445	823	water+mud	Mississippian
5W0581517060000	830124	36915	4	1	A	17600	-1200	2250	2280	594	525	446	1050	-	Mississippian
5W0581521100000	660413	36409	5	1	A	17600	-1200	2150	2160	596	525	446	962	water+mud	Mississippian
5W0661521100000	951105	-2285	3	1	A	12700	-721	1740	1750	578	524	467	1020	water+mud	Mississippian
5W0631435060000	690102	35606	2	1	A	13500	-796	1810	1830	583	527	467	1020	cond. + oil + water + mud	Mississippian
5W0601929040000	650203	35812	5	1	A	19600	-1380	2350	2380	619	541	453	964	water+mud	Mississippian
5W0542115070000	770318	35139	1	1	A	27400	-2130	3220	3240	658	556	432	1090	mud	Mississippian
5W0642014100000	640809	36145	3	1	A	17500	-1170	1990	2000	612	545	467	822	water+mud	Mississippian
5W0601635090000	610424	36579	2	1	A	17200	-1150	1890	1910	610	536	459	764	-	Mississippian
5W0652025100000	780924	35740	5	1	A	16600	-1080	1810	1820	620	547	472	743	water + oil + cond. + mud	Mississippian
5W0551929040000	650118	35057	4	1	A	24000	-1790	2900	2920	658	562	454	1130	water	Mississippian
5W0611934110000	670109	36069	5	1	A	18900	-1290	2230	2240	633	563	478	944	water+mud	Mississippian
5W0621617100000	760828	36431	3	1	A	16300	-1050	1970	1980	621	548	474	925	-	Mississippian
5W0562220060000	750407	35060	4	1	A	26900	-2060	3240	3260	677	577	456	1180	water	Mississippian
5W0591520020000	610704	35641	1	1	A	17100	-1110	2070	2090	631	566	489	985	water + cond. + mud	Mississippian
5W0522116160000	770412	35331	1	1	A	29900	-2340	3430	3440	704	591	456	1100	-	Mississippian
5W0471731060000	750224	35367	6	1	A	30000	-2350	3540	3550	707	590	456	1200	water	Mississippian
5W0602080600000	720913	35891	1	1	A	22600	-1630	2740	2760	674	585	484	1090	-	Mississippian
5W0531929070000	741030	35094	3	1	A	26600	-2000	2950	3010	710	607	488	1000	water + mud + cond.	Mississippian
5W0631714070000	730331	36003	1	1	A	16500	-1020	2050	2070	665	597	523	1040	water+mud	Mississippian
5W0461514110000	920119	80923	1	1	A	28000	-2130	3340	3340	725	614	489	1210	-	Mississippian
5W0501635070000	720411	35232	3	1	A	24600	-1800	2850	2870	714	611	501	1060	-	Mississippian
5W0511905100000	670209	35360	1	1	A	29700	-2270	3250	3270	760	641	508	992	-	Mississippian
5W0651524150000	920226	80644	1	1	A	13900	-735	1760	1760	685	627	565	1020	-	Mississippian

Location	Date	Well ID	#	S	Q	p [kPa]	z [m]	dtop [m]	dbot [m]	H ₀	H ₁₀₀₀	H ₁₀₅₀	KB [m]	Fluid recovery	Aquifer
5W0541925060000	750108	35218	5	1	A	24800	-1790	2800	2800	740	641	529	1010	water	Mississippian
5W0621630060000	800420	36399	4	3	A	17300	-1030	2010	2020	731	666	588	973	water+mud	Mississippian
5W0641532030000	801106	36704	3	1	A	15200	-824	1810	1850	721	666	598	990	water	Mississippian
5W0501606110000	861031	35127	2	2	A	26800	-1960	3030	3040	781	667	546	1080	water	Mississippian
5W0621630060000	800420	36399	4	1	A	17400	-1030	2010	2020	741	675	597	973	water+mud	Mississippian
5W0661908150000	790329	35742	4	1	B	15400	-1000	1780	1780	572	509	440	774	water+mud	Mississippian
5W0651609020000	740120	35589	2	1	B	13900	-846	1810	1820	570	516	454	964	water + mud + cond.	Mississippian
5W0682136130000	650311	35614	2	1	B	15100	-963	1670	1670	577	517	449	704	water	Mississippian
5W0661534070000	710313	35919	1	1	B	12100	-666	1630	1640	565	520	466	969	water + mud + cond.	Mississippian
5W0651505100000	680213	35768	2	1	B	13400	-796	1750	1760	572	517	457	958	water+mud	Mississippian
5W0631510140000	640803	35785	2	1	B	14700	-915	1830	1840	579	526	460	914	water	Mississippian
5W0632008130000	761212	36102	3	1	B	18600	-1300	2090	2110	598	523	439	796	water+mud	Mississippian
5W0631934020000	581110	36573	2	1	B	17300	-1180	1930	1970	592	516	438	788	water	Mississippian
5W0661625080000	660202	35990	2	1	B	12800	-735	1600	1610	571	520	482	875	water + mud + oil	Mississippian
5W0611922120000	540117	36065	5	1	B	18800	-1310	2230	2240	605	533	448	920	water	Mississippian
5W0581521100000	660402	36409	4	1	B	17400	-1180	2140	2150	597	525	447	962	oil + water	Mississippian
5W0652114060000	670807	36738	3	1	B	17500	-1180	1960	1980	598	535	457	780	water+mud	Mississippian
5W0642036060000	610207	35561	4	1	B	16900	-1130	1890	1900	597	526	450	768	water	Mississippian
5W0661518150000	700317	36196	1	1	B	12800	-728	1720	1730	577	527	469	990	water + cond. + mud + oil	Mississippian
5W0671407070000	750115	35585	2	1	B	11800	-624	1730	1750	574	533	480	1110	cond. + oil + water	Mississippian
5W0581533070000	751216	36405	2	1	B	17600	-1180	2130	2140	608	545	466	955	-	Mississippian
5W0601520120000	651010	36419	1	1	B	16400	-1070	1870	1880	603	537	464	807	water+mud	Mississippian
5W0562128110000	800123	34911	2	1	B	25100	-1910	2950	2960	651	550	437	1040	water+mud	Mississippian
5W0591631040000	650218	36411	3	1	B	17700	-1190	2160	2170	615	545	465	975	water	Mississippian
5W0651506060000	800110	36472	2	1	B	13900	-822	1840	1850	598	540	478	1020	water + cond. + mud	Mississippian
5W0661536120000	840115	36921	1	1	B	12300	-667	1690	1700	589	539	483	1030	water+mud	Mississippian
5W0611504110000	760321	36420	7	1	B	16000	-1020	1830	1830	609	548	476	807	water + oil	Mississippian
5W0632006020000	630330	36119	6	1	B	19200	-1330	2140	2150	625	552	466	812	water	Mississippian
5W0591509060000	760322	63291	1	1	B	17300	-1140	2150	2160	617	556	478	1010	water + oil	Mississippian
5W0591734070000	790118	36412	3	1	B	18100	-1230	2160	2170	623	544	463	937	water + cond.	Mississippian
5W0631501060000	701210	35786	1	1	B	14700	-892	1800	1830	608	549	483	914	water	Mississippian
5W0671924160000	960128	-3439	3	1	B	14000	-826	1600	1600	605	546	483	773	water+mud	Mississippian
5W0611534100000	760908	36428	2	1	B	15500	-965	1870	1890	613	554	485	907	water	Mississippian
5W0522123130000	810224	34860	1	1	B	29200	-2300	3360	3370	680	562	431	1060	mud + cond. + water	Mississippian

Location	Date	Well ID	#	S	Q	p [kPa]	z [m]	dtop [m]	dbot [m]	H ₀	H ₁₀₄₀	H ₁₀₉₀	KB [m]	Fluid recovery	Aquifer
5W0551712060000	740707	35287	2	1	B	21600	-1550	2510	2540	643	567	470	965	water + mud + cond.	Mississippian
5W0621504060000	780924	36313	3	1	B	15700	-987	1900	1920	616	552	481	920	-	Mississippian
5W0581834100000	680928	35932	2	1	B	19800	-1380	2420	2430	639	561	472	1040	water + mud + cond.	Mississippian
5W0561708050000	771229	35091	4	1	B	20800	-1470	2640	2650	650	569	475	1170	-	Mississippian
5W0651929070000	780406	36734	4	1	B	16500	-1050	1830	1850	630	567	493	786	water + mud + cond.	Mississippian
5W0531702110000	640716	34883	1	1	B	23400	-1720	2620	2650	664	574	468	905	water+mud	Mississippian
5W0591908100000	771015	36150	3	1	B	21200	-1500	2410	2430	659	578	483	913	water + cond.	Mississippian
5W0611510060000	890828	80687	1	1	B	16200	-1020	1850	1860	636	568	495	834	water + mud + cond.	Mississippian
5W0592026070000	771211	36722	2	1	B	21200	-1500	2520	2540	665	578	483	1010	water + cond.	Mississippian
5W0531708110000	650707	34882	12	1	B	24100	-1780	2880	2700	680	582	474	916	mud	Mississippian
5W0501718100000	650128	35258	1	1	B	26900	-2050	3060	3090	694	587	466	1050	water + cond.	Mississippian
5W0551814100000	750303	35134	1	1	B	22100	-1580	2600	2620	672	586	487	1020	water	Mississippian
5W0551817110000	761215	35412	5	1	B	23000	-1660	2680	2690	685	594	491	1010	-	Mississippian
5W0621620100000	760202	36375	1	1	B	16600	-1030	1950	1960	662	597	522	927	mud + water	Mississippian
5W0571927060000	800623	34949	1	1	B	22200	-1560	2780	2800	701	616	516	1220	water + cond.	Mississippian
5W0602006100000	800311	36556	2	1	B	22000	-1540	2540	2560	704	616	517	1000	mud + water	Mississippian
5W0541729140000	820412	34751	1	2	B	23100	-1640	2560	2570	715	624	520	923	water + cond.	Mississippian
5W0581704070000	770809	34997	3	1	B	20200	-1350	2590	2630	705	630	539	1240	mud + cond. + water	Mississippian
5W0561712100000	800709	34959	4	1	B	21600	-1480	2410	2430	718	637	540	927	water + cond. + mud	Mississippian
5W0592029110000	770128	36339	5	1	B	22400	-1560	2540	2550	725	636	535	978	water+mud	Mississippian
5W0671614070000	710116	35599	1	1	C	12200	-693	1630	1650	547	503	448	943	-	Mississippian
5W0612035100000	640119	36061	1	1	C	19000	-1340	2200	2210	597	522	437	872	water + mud + cond.	Mississippian
5W0611617060000	790822	36400	5	1	C	16700	-1120	1990	2010	590	517	442	886	water + cond. + mud	Mississippian
5W0651522020000	590322	36729	4	1	C	13200	-775	1760	1770	573	519	459	993	water	Mississippian
5W0671926040000	640811	35703	8	1	C	14400	-888	1660	1670	584	523	459	761	water+oil+mud	Mississippian
5W0671530100000	650128	35616	1	1	C	12200	-666	1620	1630	574	530	475	956	water + mud + oil	Mississippian
5W0661519050000	700304	36049	2	2	C	12800	-724	1690	1710	580	531	473	972	water+mud	Mississippian
5W0661527100000	810308	36753	5	1	C	12600	-703	1660	1680	580	532	475	967	water+mud	Mississippian
5W0621812110000	690717	36451	2	1	C	17200	-1150	2030	2050	603	536	459	888	water	Mississippian
5W0621614100000	600307	36684	3	1	C	15700	-1000	1970	1980	596	539	468	970	-	Mississippian
5W0651930020000	810108	36735	3	1	C	16300	-1060	1810	1810	601	538	464	747	water + cond.	Mississippian
5W0591528080002	601229	35864	1	1	C	17100	-1130	2070	2090	606	546	469	951	oil + mud	Mississippian
5W0632006020000	630329	36119	5	1	C	19100	-1330	2140	2150	618	542	456	812	oil + water	Mississippian
5W0641922070000	570310	35719	6	1	C	16800	-1110	1850	1860	608	537	461	746	water	Mississippian

Location	Date	Well ID	#	S	Q	p [kPa]	z [m]	dtop [m]	dbot [m]	H ₀	H ₁₀₄₀	H ₁₀₉₀	KB [m]	Fluid recovery	Aquifer
5W0541629060000	681009	35004	4	1	C	21200	-1530	2450	2470	630	548	453	921	water+mud	Mississippian
5W0632106100000	640106	35759	4	1	C	20000	-1410	2250	2260	624	550	460	836	water+mud	Mississippian
5W0571825100000	770129	34998	9	1	C	20200	-1430	2640	2650	627	550	459	1200	water	Mississippian
5W0611523100000	771025	36425	2	2	C	15500	-980	1870	1880	604	539	470	881	water + mud + cond.	Mississippian
5W0611523120000	630729	36426	4	1	C	15800	-1010	1850	1860	607	539	468	853	water+mud	Mississippian
5W0582033100000	641211	35618	1	1	C	21800	-1590	2560	2570	637	547	449	978	water	Mississippian
5W0542336020000	660222	35073	2	2	C	28900	-2280	3360	3380	673	553	423	1100	water	Mississippian
5W0531934020000	740919	35136	11	1	C	24900	-1890	2870	2880	653	551	439	985	water	Mississippian
5W0591929060000	610831	36542	5	1	C	20800	-1480	2450	2480	633	559	465	991	water	Mississippian
5W0562122130000	770726	35284	3	1	C	25300	-1930	3040	3060	658	550	436	1120	water	Mississippian
5W0522133100000	760206	35013	12	1	C	29700	-2340	3390	3400	680	571	438	1050	water+mud	Mississippian
5W0632205060000	620202	35716	6	1	C	21000	-1500	2360	2380	638	558	464	881	mud + water + cond.	Mississippian
5W0622027100000	610815	36576	6	1	C	19000	-1310	2130	2160	629	552	467	838	mud + water + cond.	Mississippian
5W0591506110000	560713	36548	5	1	C	17900	-1200	2220	2220	625	554	474	1020	water+mud	Mississippian
5W0621614100000	600310	36684	4	1	C	16700	-1080	2040	2050	620	557	482	970	water+mud	Mississippian
5W0481814040000	650524	35168	1	1	C	30900	-2340	3450	3490	808	689	550	1140	water + cond.	Mississippian
5W0601507100000	661001	36417	2	1	C	16700	-1080	1930	1980	622	557	482	853	water + cond.	Mississippian
5W0632204100000	770317	36045	2	1	C	20800	-1480	2320	2350	643	559	485	841	water+mud	Mississippian
5W0591801110000	681003	36072	1	1	C	19500	-1360	2400	2410	638	561	473	1040	water	Mississippian
5W0511821060000	860128	68690	1	1	C	26700	-2050	3060	3070	673	567	447	1010	-	Mississippian
5W0561932010000	560321	35411	4	1	C	22600	-1650	2970	2980	654	565	464	1330	-	Mississippian
5W0531918100000	750322	35249	3	1	C	26100	-1990	2990	3000	673	568	451	994	water	Mississippian
5W0552209100000	830510	34742	1	1	C	27900	-2160	3230	3250	684	575	449	1080	-	Mississippian
5W0532117100000	760408	35083	5	1	C	29400	-2300	3060	3390	696	582	449	1070	-	Mississippian
5W0542125060000	710313	35281	8	1	C	26600	-2030	3200	3280	683	577	458	1170	mud	Mississippian
5W0611904100000	660304	36059	7	1	C	19700	-1350	2300	2320	652	581	492	955	water + mud + cond.	Mississippian
5W0682031100000	890809	63321	1	1	C	14200	-820	1530	1540	626	572	508	715	water + mud + cond. + oil	Mississippian
5W0571811100000	770404	35054	5	2	C	20900	-1470	2790	2800	660	579	485	1320	water + cond. + mud	Mississippian
5W0562313040000	650210	35269	3	1	C	27500	-2110	3240	3300	694	585	462	1130	water+mud	Mississippian
5W0531917090000	641102	35413	8	1	C	26300	-2000	2970	2980	689	578	460	985	-	Mississippian
5W0491822100000	660419	35256	2	1	C	28600	-2220	3260	3270	702	583	455	1050	-	Mississippian
5W0561635070000	950120	-1736	1	1	C	19700	-1350	2320	2330	659	581	492	979	water	Mississippian
5W0531922070000	731227	35264	3	1	C	25700	-1930	2890	2930	689	589	473	963	water	Mississippian
5W0541710020000	650519	34873	4	1	C	22600	-1630	2550	2560	674	585	484	922	water	Mississippian

Location	Date	Well ID	#	S	Q	p [kPa]	z [m]	dtop [m]	dbot [m]	H ₀	H ₁₀₄₀	H ₁₀₉₀	KB [m]	Fluid recovery	Aquifer
5W0661519050000	700304	36049	2	1	C	13300	-724	1690	1710	630	580	520	972	water+mud	Mississippian
5W0522013090000	760320	35200	1	1	C	27700	-2120	3150	3160	700	595	471	1030	mud	Mississippian
5W0672220100000	720315	35650	3	1	C	18400	-1220	1920	1940	655	583	501	701	-	Mississippian
5W0561909090000	740128	35174	8	1	C	23200	-1690	2860	2910	680	584	480	1170	mud	Mississippian
5W0501609060000	670609	35121	3	2	C	25900	-1950	2950	3010	694	589	472	1060	water + cond. + oil	Mississippian
5W0551716080000	770212	35071	1	2	C	21500	-1510	2460	2490	677	597	501	953	water + mud + cond.	Mississippian
5W0521520040020	650128	34839	4	1	C	22800	-1640	2560	2570	685	595	492	921	mud	Mississippian
5W0501712080000	681001	35245	1	1	C	26000	-1950	2980	3030	701	598	482	1040	water + mud + cond.	Mississippian
5W0491836060000	660404	35165	2	1	C	27800	-2110	3140	3180	721	615	490	1040	water + cond.	Mississippian
6W0610204070000	700619	38988	2	1	C	30000	-2320	3630	3640	733	620	486	1310	mud	Mississippian
5W0511621080000	740428	35102	1	1	C	24700	-1810	2820	2860	709	611	500	1020	water	Mississippian
5W0511609110000	650411	35039	6	1	C	24700	-1800	2910	2920	715	621	510	1110	water + cond. + mud	Mississippian
5W0592419070000	620407	36582	7	1	C	26600	-1990	3180	3230	725	617	498	1190	mud + water + cond.	Mississippian
5W0491712110000	740917	35395	8	1	C	27300	-2060	3200	3220	731	616	493	1140	-	Mississippian
5W0521918100000	811005	34810	7	1	C	28200	-2140	3170	3180	737	624	497	1030	mud + cond.	Mississippian
5W0481635100000	711016	35072	4	1	C	27100	-2020	3150	3160	741	636	514	1130	water + cond.	Mississippian
5W0621908070000	830830	36849	1	1	C	19150	-1260	2160	2190	705	617	531	907	water+gas	Mississippian
5W0602333060000	731016	35761	4	1	C	24000	-1710	2780	2790	735	642	534	1070	mud + water + cond.	Mississippian
5W0502214020000	710808	35385	11	1	C	34200	-2700	3910	3910	788	652	498	1200	water	Mississippian
5W0522002100000	810114	34799	2	1	C	28700	-2170	3210	3260	762	643	514	1040	water + cond.	Mississippian
5W0592202100000	770107	35692	8	1	C	26000	-1890	3020	3030	764	658	542	1130	water+mud	Mississippian
5W0542412070000	730417	35040	8	1	C	32800	-2540	3730	3800	800	675	527	1260	water	Mississippian
5W0501618100000	630927	35158	1	1	C	25800	-1910	2940	2980	786	619	503	1040	water	Mississippian
5W0481814040000	650714	35168	2	1	C	29500	-2320	3460	3520	884	571	439	1140	water+mud	Mississippian
5W0482018060000	600305	35254	10	1	C	35900	-2830	4110	4150	833	689	527	1320	water + cond.	Mississippian
5W0571606100000	761214	35001	12	1	C	20400	-1390	2450	2470	769	610	518	1070	water	Mississippian
5W0471615060020	620501	34840	6	1	C	29500	-2190	3460	3610	814	701	589	1270	water + cond. + mud	Mississippian
5W0471527110000	730211	35248	12	1	C	27900	-2030	3190	3190	814	705	579	1170	water	Mississippian
5W0511813150000	641231	35140	1	1	C	26600	-1990	2990	3000	825	617	498	1010	mud	Mississippian
5W0671924140000	740203	35702	2	1	A	22000	-1510	2260	2300	734	646	547	768	water	Wabamun
5W0682033120000	670221	35609	5	1	A	23400	-1600	2330	2350	786	694	588	744	water	Wabamun
5W0571723100000	760304	35369	4	1	A	25200	-1730	2850	2860	838	740	627	1120	mud + water	Wabamun
5W0642417100000	770917	35565	5	1	A	30400	-2210	3090	3090	895	770	633	882	water + cond. + mud	Wabamun
6W0690508050000	701013	38861	3	1	A	35200	-2630	3230	3310	956	820	662	660	water + mud	Wabamun

Location	Date	Well ID	#	S	Q	p [kPa]	z [m]	dtop [m]	dbot [m]	H ₀	H ₁₀₀₀	H ₁₀₄₀	KB [m]	Fluid recovery	Aquifer
6W0680421100000	661223	38862	6	1	A	35800	-2660	3300	3330	983	849	888	669	water	Wabamun
5W0611828080000	600305	36562	3	1	B	23800	-1730	2640	2640	697	603	496	910	water + cond.	Wabamun
5W0651801100000	610116	36633	10	1	B	21900	-1540	2320	2340	696	607	508	803	mud + cond. + water	Wabamun
5W0651911100000	601124	36620	5	1	B	23000	-1630	2420	2440	719	624	521	812	water	Wabamun
5W0641814020000	640211	36104	1	1	B	21000	-1440	2240	2260	707	618	524	821	water + mud	Wabamun
5W0651923020000	610309	36621	1	1	B	23100	-1610	2420	2450	741	654	550	839	water + mud	Wabamun
5W0662109100000	641112	35619	5	1	B	25300	-1780	2510	2520	807	700	586	741	water	Wabamun
5W0662028020000	690302	35701	5	1	B	24000	-1650	2450	2480	791	702	594	801	water + cond. + mud	Wabamun
5W0692107030000	570405	36666	7	1	B	24700	-1690	2330	2350	820	731	620	651	water + cond.	Wabamun
5W0571712020000	860402	69685	2	1	B	24400	-1630	2720	2730	858	762	652	1100	water + cond. + mud	Wabamun
6W0680417060000	650321	38917	2	1	B	35700	-2670	3350	3380	975	829	689	687	water + mud	Wabamun
6W0670414110000	820709	39215	3	1	B	36000	-2680	3390	3460	989	849	687	718	water + mud	Wabamun
5W0651728010000	820226	36871	1	1	C	19600	-1350	2240	2250	640	571	483	885	mud + water + cond.	Wabamun
5W0601625150000	570109	36691	6	1	C	21600	-1510	2320	2330	699	607	510	814	water + cond.	Wabamun
5W0671834040000	630225	35540	4	1	C	21300	-1440	2210	2230	731	648	552	875	cond. + water + mud	Wabamun
5W0681812100000	660419	35544	4	1	C	20600	-1360	2290	2300	740	659	567	917	water	Wabamun
5W0692221040000	580623	36647	2	2	C	24500	-1720	2410	2420	763	681	571	698	water	Wabamun
5W0662008100000	720321	36007	2	1	C	24400	-1700	2440	2460	793	692	582	742	water	Wabamun
5W0632028020000	601212	36569	7	1	C	25900	-1840	2620	2630	802	699	582	787	water + cond. + mud	Wabamun
5W0662402100000	620815	36619	3	1	C	28500	-2060	2950	2960	841	733	605	897	water + cond. + mud	Wabamun
5W0692107030000	570403	36666	6	1	C	24300	-1680	2300	2310	826	722	613	651	water + mud + cond.	Wabamun
5W0692106130000	560924	35684	3	1	C	25000	-1710	2330	2350	844	740	628	643	water + mud	Wabamun
5W0632633040000	641201	35697	2	1	C	33000	-2460	3350	3360	910	775	626	899	oil	Wabamun
5W0662502110000	660321	36175	2	1	C	30100	-2160	2950	2980	914	790	655	792	mud	Wabamun
6W0690521100000	690320	38920	2	1	C	35300	-2650	3300	3320	947	810	651	661	water + mud + cond.	Wabamun
6W0680404060000	681129	38919	2	2	C	35400	-2650	3370	3420	959	820	661	727	water + cond.	Wabamun
6W0640415060000	621215	38878	7	2	C	38500	-2930	3820	3830	1000	844	671	887	water + cond.	Wabamun
6W0670420100000	660411	38916	1	1	C	36400	-2720	3310	3350	990	848	684	601	water + cond. + mud	Wabamun
6W0630131040000	670915	38974	2	1	C	36000	-2670	3550	3570	988	859	697	899	water	Wabamun
5W0571926040000	651122	35122	1	1	C	29400	-1950	3050	3060	1045	932	799	1100	water	Wabamun
5W0522123130000	810308	34860	4	1	C	37100	-2660	3730	3760	1121	976	810	1060	water + mud + cond.	Wabamun
5W0661519050000	700301	36049	1	1	A	20600	-1400	2380	2390	703	619	527	972	oil + cond. + mud	Winterburn
5W0671502010000	710308	35728	1	1	A	20600	-1320	2320	2360	779	699	607	990	oil	Winterburn
5W0652114060000	670818	36738	5	1	A	26300	-1840	2610	2620	840	738	620	780	water + mud	Winterburn

Location	Date	Well ID	#	S	Q	p [kPa]	z [m]	dtop [m]	dbot [m]	H ₀	H ₁₀₄₀	H ₁₀₉₀	KB [m]	Fluid recovery	Aquifer
5W0681709100000	650310	35757	4	1	A	22200	-1430	2330	2340	836	746	646	907	water + mud	Winterburn
5W0562118060000	780510	35405	3	1	A	34900	-2590	3610	3630	970	831	674	1020	water + cond. + mud	Winterburn
5W0501520060000	780713	35384	2	1	B	29100	-2260	3260	3320	706	592	461	1020	water	Winterburn
5W0641804020000	611103	36624	5	1	B	23500	-1670	2450	2460	728	633	528	791	water + cond.	Winterburn
5W0642316100000	780209	36093	2	1	B	29000	-2110	2920	2940	839	732	602	805	water + cond. + mud	Winterburn
5W0632202020000	630315	35972	3	1	B	28900	-2090	2950	2960	855	743	613	871	water + oil	Winterburn
6W0630131040000	671025	38974	5	1	B	36400	-2790	3590	3790	919	778	614	889	mud + water	Winterburn
5W0641802040000	590328	36085	6	1	B	30700	-2240	3040	3070	889	769	631	821	water + mud	Winterburn
6W0680513110000	640418	38908	3	1	B	36400	-2750	3300	3330	961	818	654	578	water + mud	Winterburn
6W0680403100000	660302	38912	5	1	B	35800	-2690	3410	3480	954	819	658	728	water	Winterburn
5W0581715060000	590212	35635	2	1	B	27500	-1900	3060	3080	900	795	672	1180	water	Winterburn
5W0541919020000	660412	35215	4	1	B	33700	-2480	3520	3540	948	823	672	1040	water + mud	Winterburn
5W0651917100000	590304	36657	8	1	B	25700	-1720	2450	2460	900	799	683	743	water + oil + mud	Winterburn
6W0630213120000	641114	38969	4	1	B	37000	-2780	3780	3850	989	847	680	991	water + mud	Winterburn
6W0670531070000	680322	39031	4	1	B	38600	-2930	3500	3610	1014	853	680	685	water + mud	Winterburn
5W0651921060000	780903	35723	4	1	B	25500	-1690	2470	2490	910	809	695	790	water	Winterburn
6W0660436060000	680314	38864	3	1	B	37900	-2860	3490	3610	1007	855	684	753	water	Winterburn
5W0651911040000	600901	36733	8	1	B	25400	-1680	2470	2480	907	810	695	794	water + mud + oil + cond.	Winterburn
5W0471408040000	800205	34966	5	1	B	34800	-2530	3750	3780	1021	881	724	1230	mud + water + cond.	Winterburn
5W0501520090000	810923	34758	1	1	C	29100	-2270	3260	3270	701	582	451	993	water	Winterburn
5W0661825080000	660222	35990	3	1	C	20500	-1400	2280	2280	683	609	517	875	oil + mud + water + cond.	Winterburn
5W0641814020000	640215	36104	2	1	C	22700	-1600	2430	2460	711	625	523	821	water + cond.	Winterburn
5W0661614020000	660405	36774	1	1	C	21100	-1430	2290	2300	720	638	543	856	water	Winterburn
5W0641804020000	611106	36624	6	1	C	24000	-1700	2500	2510	741	652	544	791	water + cond. + mud	Winterburn
5W0631818020000	591121	36330	7	1	C	24400	-1730	2520	2530	758	662	552	799	water + mud	Winterburn
5W0661411120000	590214	36392	5	1	C	19400	-1250	2410	2420	733	652	564	1160	water + mud	Winterburn
5W0692105090020	571124	36811	2	1	C	24200	-1700	2360	2360	767	672	563	663	water + cond.	Winterburn
5W0681919160000	620227	35998	3	1	C	23500	-1600	2350	2360	796	703	598	759	mud + water + cond.	Winterburn
5W0662502110000	660323	36175	3	1	C	30100	-2210	3000	3050	856	740	605	792	water + mud	Winterburn
5W0652425100000	651003	36070	2	1	C	28900	-2090	2940	2970	851	743	613	856	water + mud	Winterburn
6W0630101100000	601016	39110	7	2	C	35100	-2660	3650	3690	916	780	623	1010	mud + cond. + water	Winterburn
5W0551817020000	800909	34993	3	1	C	31700	-2330	3320	3360	901	777	635	989	water + cond.	Winterburn
5W0662008100000	720305	36007	1	1	C	25700	-1760	2490	2500	859	759	643	742	mud + water	Winterburn
5W0591633100000	660119	35665	2	1	C	25600	-1750	2670	2680	851	759	644	924	water	Winterburn

Location	Date	Well ID	#	S	Q	p [kPa]	z [m]	dtop [m]	dbot [m]	H ₀	H ₁₀₀₀	H ₁₀₀₀	KB [m]	Fluid recovery	Aquifer
5W0551816060000	590326	35356	5	1	C	30500	-2210	3180	3190	899	779	842	977	water	Winterburn
5W0621726100000	640214	35962	2	1	C	24200	-1610	2530	2550	850	762	653	932	water + cond.	Winterburn
5W0601622090002	950816	-2075	1	1	C	23300	-1520	2350	2500	852	764	659	824	water + mud	Winterburn
5W0632109100000	680126	35997	3	1	C	28400	-2000	2800	2860	890	784	656	808	mud	Winterburn
5W0652334100000	721009	35746	3	1	C	28200	-1980	2720	2760	885	784	657	742	water + mud + cond.	Winterburn
5W0542011100000	700308	35389	2	1	C	33900	-2500	3590	3620	949	823	670	1090	water	Winterburn
6W0661219080000	700901	80070	1	2	C	49400	-3950	4980	5180	1086	892	670	1010	water + mud + cond.	Winterburn
5W0592434040000	630614	35534	5	1	C	34600	-2550	3670	3760	974	841	686	1130	water + cond.	Winterburn
5W0621916040000	590426	35775	11	1	C	27000	-1830	2710	2720	921	816	695	874	mud + water	Winterburn
5W0651923080000	830216	35509	3	1	C	25000	-1640	2490	2520	907	810	698	849	water + cond. + mud	Winterburn
5W0541919020000	680414	35215	5	1	C	33300	-2420	3450	3490	974	844	694	1040	water	Winterburn
5W0651923080000	830212	35509	2	2	C	25200	-1650	2490	2520	923	820	707	849	mud + oil + cond.	Winterburn
5W0631918100000	621019	35999	3	1	C	27400	-1830	2620	2640	964	856	732	791	water + cond. + mud	Winterburn
5W0622023060000	670901	35989	3	1	C	28300	-1900	2770	2790	985	874	747	880	water + cond. + mud	Winterburn
5W0551919140020	690221	35337	3	1	C	33000	-2330	3520	3620	1034	905	756	1150	water	Winterburn
5W0681714080000	770307	35571	3	1	C	22700	-1370	2260	2290	944	855	753	893	water + mud	Winterburn
5W0591626070000	770206	35879	4	1	C	24100	-1730	2620	2640	722	632	524	891	mud + water	Winterburn
5W0582026040000	630222	36354	8	1	A	32300	-2360	3280	3290	932	806	661	929	water + cond.	Woodbend
6W0630131040000	671026	38974	6	1	A	38100	-2900	3720	3790	982	834	663	889	water + mud	Woodbend
5W0602110060000	650228	35658	1	1	A	33700	-2470	3460	3480	963	833	682	1010	water + cond.	Woodbend
5W0591631040000	650312	36411	6	1	B	27000	-1880	2850	2870	872	766	645	975	water	Woodbend
5W0561622090000	691113	35293	3	1	B	29600	-2120	3080	3120	901	781	648	962	water + cond.	Woodbend
5W0551817100000	650412	35290	3	1	B	31900	-2330	3310	3330	915	797	653	988	water	Woodbend
5W0592007110000	620516	35890	1	1	B	32100	-2340	3450	3460	935	806	662	1110	water + cond.	Woodbend
5W0592017100000	610418	35898	5	1	B	33000	-2420	3520	3530	945	815	666	1100	water	Woodbend
5W0571629100000	610516	34938	9	1	B	29200	-2060	3130	3140	912	802	671	1080	water + cond.	Woodbend
5W0632522040000	850330	36983	1	1	B	36200	-2720	3580	3600	975	828	665	889	water + mud	Woodbend
5W0592434040000	630623	35534	8	1	B	36600	-2730	3850	3900	1008	857	693	1130	water + cond.	Woodbend
5W0592434040000	630618	35534	7	1	B	36200	-2690	3810	3830	994	858	695	1130	water + cond.	Woodbend
5W0522116160000	770515	35331	6	1	B	39700	-3020	4110	4120	1021	871	693	1200	water + cond.	Woodbend
5W0602632100000	690905	36692	6	1	B	38300	-2850	4080	4090	1055	904	732	1240	water	Woodbend
6W0670712120000	701231	38976	1	1	B	41500	-3140	4070	4080	1086	928	741	928	water	Woodbend
5W0692325030000	560111	35849	1	1	C	27600	-1980	2720	2730	835	725	601	748	water	Woodbend
5W0692210070000	560526	36265	1	1	C	27000	-1920	2590	2590	831	726	605	668	oil	Woodbend

Location	Date	Well ID	#	S	Q	p [kPa]	z [m]	dtop [m]	dbot [m]	H ₀	H ₁₀₀₀	H ₁₀₀₀	KB [m]	Fluid recovery	Aquifer
5W0632509120000	581101	35653	3	1	C	35300	-2680	3500	3510	921	780	621	833	oil + mud	Woodbend
5W0602320100000	600319	36581	4	1	C	34000	-2540	3550	3560	935	793	640	1030	water + cond.	Woodbend
5W0541814070000	860419	68686	1	1	C	31500	-2300	3290	3300	912	788	646	984	mud	Woodbend
5W0591631040000	650308	36411	5	2	C	28100	-1790	2760	2770	870	788	651	975	water	Woodbend
5W0552260800020	660719	34891	8	1	C	38000	-2910	3840	3850	959	815	644	929	n/a	Woodbend
5W0532008100000	630330	35350	3	1	C	35900	-2710	3740	3750	950	809	647	1040	water	Woodbend
5W0552260800020	660707	34891	3	1	C	38400	-2940	3860	3900	982	824	651	929	n/a	Woodbend
5W0601415060000	700116	35691	6	1	C	27300	-1890	2660	2670	889	786	663	764	oil + cond. + mud	Woodbend
5W0551920100000	660223	35391	5	1	C	34300	-2550	3650	3670	955	812	658	1130	water + cond.	Woodbend
5W0512030060000	710604	35386	5	1	C	38800	-2970	4050	4200	994	833	659	1080	water	Woodbend
5W0551914020000	580223	34941	5	2	C	33200	-2440	3440	3470	940	814	685	990	water	Woodbend
5W0551923120000	690124	35283	1	1	C	33200	-2440	3520	3520	946	814	685	1080	water	Woodbend
5W0601722100000	581015	35935	4	1	C	29400	-2080	2880	2870	921	802	669	792	water + cond.	Woodbend
5W0601620120000	630924	35936	3	1	C	28900	-1840	2660	2660	896	797	676	816	water	Woodbend
5W0632509120000	581031	35653	2	1	C	35600	-2660	3480	3500	968	829	669	833	cond. + oil + mud	Woodbend
5W0592434040000	630616	35534	6	1	C	35400	-2640	3760	3780	971	830	671	1130	water + cond.	Woodbend
5W0541719110000	711012	34872	3	1	C	31400	-2260	3190	3200	942	818	677	942	mud	Woodbend
5W0622633100000	590910	36250	2	1	C	36400	-2730	3640	3650	988	838	674	924	water + mud	Woodbend
5W0632604160000	600317	35633	4	1	C	36000	-2690	3610	3630	972	839	677	934	water + cond. + mud	Woodbend
5W0592419070000	620527	36582	15	1	C	37000	-2780	3980	3990	993	847	680	1190	water	Woodbend
6W0670432100000	650521	38894	10	1	C	39700	-3030	3720	3760	1008	861	683	693	water + cond. + mud	Woodbend
5W0592007110000	620518	35890	2	2	C	32700	-2360	3470	3480	968	845	698	1110	mud	Woodbend
6W0630101100000	601022	39110	9	1	C	37300	-2790	3790	3820	1011	866	698	1010	water + cond. + mud	Woodbend
5W0632509070000	860212	50843	1	1	C	36300	-2690	3530	3550	1011	868	705	836	water + mud	Woodbend
6W0580114060000	790303	39196	1	1	C	42800	-3300	4490	4520	1060	895	703	1190	water + cond.	Woodbend
5W0582513130000	680322	35668	6	1	C	38200	-2860	3900	3970	1031	884	712	1050	water + cond.	Woodbend
5W0492235070000	810307	-1735	7	1	C	44000	-3400	4650	4840	1092	913	715	1240	mud	Woodbend
5W0522023060000	800514	34944	5	2	C	37600	-2790	3800	3810	1045	895	726	1020	mud	Woodbend
6W0610204070000	700720	38988	4	1	C	42000	-3200	4510	4550	1076	917	728	1310	water	Woodbend
5W0551729150000	541013	34923	18	1	C	30900	-2150	3200	3200	1005	879	740	1060	cond.	Woodbend
5W0581928110000	600207	35708	4	1	C	33200	-2360	3310	3320	1029	894	745	966	water + cond.	Woodbend
5W0532312060000	781203	35388	7	1	C	43600	-3340	4370	4380	1101	934	737	1020	n/a	Woodbend
6W0620934090000	761217	38873	5	1	C	48900	-3830	5240	5530	1150	963	743	1410	water + cond. + mud	Woodbend
6W0610433070000	730514	39146	1	1	C	44000	-3360	4430	4460	1128	953	755	1100	water	Woodbend

Location	Date	Well ID	#	S	Q	p [kPa]	z [m]	dtop [m]	dbot [m]	H ₀	H ₁₀₄₀	H ₁₀₉₀	KB [m]	Fluid recovery	Aquifer
5W0561932010000	560517	35411	17	1	C	32700	-2320	3630	3650	1010	885	738	1330	water + cond.	Woodbend
5W0571728070000	680408	35294	3	1	B	31300	-2300	3550	3610	900	768	627	1260	water	Beaverhill Lake
5W0591929060000	611008	36542	8	1	B	33400	-2490	3460	3480	912	784	634	991	water	Beaverhill Lake
5W0611828080000	600325	36562	4	1	B	31900	-2340	3230	3250	912	787	643	910	water	Beaverhill Lake
5W0581516060000	790308	35789	3	1	B	29900	-2140	3150	3180	907	791	656	1010	water	Beaverhill Lake
5W0601807100000	680127	36712	5	1	B	33400	-2470	3340	3360	925	804	654	864	water	Beaverhill Lake
5W0541719110000	711024	34872	5	1	B	34400	-2560	3500	3540	951	812	657	942	mud	Beaverhill Lake
5W0612332060000	700902	35955	2	1	B	36100	-2720	3760	3790	960	818	656	1060	water + mud	Beaverhill Lake
5W0601722100000	581021	35935	5	1	B	31000	-2230	3020	3030	934	809	669	792	water	Beaverhill Lake
5W0521610060000	680415	34886	2	1	B	35800	-2680	3630	3660	971	829	668	953	water + cond. + mud	Beaverhill Lake
5W0641804020000	611122	36624	7	1	B	30300	-2160	2910	2950	933	810	674	791	water	Beaverhill Lake
5W0632109100000	680115	35997	1	1	B	33400	-2450	3250	3260	954	824	674	808	water + mud + cond.	Beaverhill Lake
5W0581511060000	761219	35055	3	1	B	30300	-2150	3290	3300	938	820	684	1130	water	Beaverhill Lake
5W0531522040000	630427	35096	7	1	B	33400	-2440	3360	3370	969	834	684	927	water + cond.	Beaverhill Lake
5W0621906140000	380803	36253	1	1	B	32600	-2360	3220	3290	970	835	689	869	water + cond.	Beaverhill Lake
5W0641804100000	610908	36625	1	1	B	30400	-2130	2930	2960	972	850	713	797	oil	Beaverhill Lake
5W0692519070030	820920	35510	1	1	C	32900	-2460	3220	3230	898	765	617	769	water + mud + cond.	Beaverhill Lake
5W0631825100000	630412	36343	7	2	C	29800	-2160	2950	2980	883	761	627	821	water + mud + cond.	Beaverhill Lake
5W0541632100000	691121	34874	1	1	C	33300	-2480	3370	3390	918	784	634	890	water + mud	Beaverhill Lake
5W0581936060000	610414	36543	3	1	C	32600	-2400	3440	3450	923	795	649	1050	water	Beaverhill Lake
5W0631927080000	880305	50839	3	1	C	30600	-2210	3010	3020	909	789	652	800	mud + oil + water	Beaverhill Lake
5W0611919020000	580313	35712	9	1	C	32300	-2370	3270	3270	922	796	651	897	water	Beaverhill Lake
5W0601805070000	680820	35557	3	1	C	32200	-2360	3220	3230	923	796	651	862	water + mud + cond.	Beaverhill Lake
5W0652023100000	790121	36737	3	B1	C	31300	-2270	3010	3040	922	798	657	768	water + mud + cond.	Beaverhill Lake
5W0622021110000	620106	36574	9	1	C	32400	-2370	3210	3220	936	806	660	851	water	Beaverhill Lake
5W0622024040000	600224	36575	3	2	C	32400	-2370	3250	3260	942	806	660	891	water + cond.	Beaverhill Lake
5W0601807100000	680123	36712	4	1	C	32400	-2370	3220	3230	935	806	660	864	cond. + water	Beaverhill Lake
5W0481901060000	730215	35167	3	1	C	44000	-3460	4580	4590	1016	853	655	1120	water + mud	Beaverhill Lake
5W0541528100000	710627	35280	2	1	C	32800	-2400	3250	3260	945	815	667	861	mud + cond.	Beaverhill Lake
5W0531522040000	650502	35096	9	1	C	33200	-2430	3350	3360	955	824	675	927	water + mud	Beaverhill Lake
5W0672208160000	840928	36962	1	1	C	32700	-2380	3100	3130	950	825	678	718	water + mud	Beaverhill Lake
5W0601924060000	680122	35993	1	1	C	32400	-2350	3370	3370	952	826	680	1020	mud + water + cond.	Beaverhill Lake
5W0641810040000	611224	36627	6	1	C	30400	-2160	2950	2960	945	820	683	804	mud + cond. + oil	Beaverhill Lake
5W0531522040000	630423	35096	4	1	C	33600	-2460	3400	3400	963	833	682	927	water + mud	Beaverhill Lake

Location	Date	Well ID	#	S	Q	p [kPa]	z [m]	dtop [m]	dbot [m]	H ₀	H ₁₀₀₀	H ₁₀₀₀	KB [m]	Fluid recovery	Aquifer
5W0541505070000	690414	35279	3	1	C	33400	-2440	3320	3370	969	834	684	891	water + cond. + mud	Beaverhill Lake
5W0631825120000	731017	36109	1	1	C	29800	-2100	2900	2990	933	821	687	805	cond. + mud + water	Beaverhill Lake
5W0592519140000	800518	36486	3	1	C	40500	-3100	4370	4380	1029	870	688	1270	water + mud + cond.	Beaverhill Lake
5W0632202020000	630325	35972	4	1	C	34200	-2500	3370	3380	982	852	698	871	water	Beaverhill Lake
5W0632106100000	640203	35759	5	1	C	34100	-2480	3320	3320	990	862	709	836	water	Beaverhill Lake
5W0671815100000	630122	36317	1	1	C	29300	-2020	2820	2860	973	852	720	814	water + oil + cond.	Beaverhill Lake
5W0511727100000	580520	34920	9	1	C	38000	-2840	3810	3850	1032	885	714	1000	water	Beaverhill Lake
5W0541723100000	720327	35098	5	1	C	34400	-2480	3420	3450	1028	892	737	942	mud + water + cond.	Beaverhill Lake
5W0612403100000	590501	36565	11	1	C	38400	-2840	3960	3970	1075	924	751	1130	water + mud	Beaverhill Lake
5W0652423100000	631016	35733	4	1	C	35700	-2580	3420	3440	1058	919	759	884	cond. + oil	Beaverhill Lake
5W0671803040000	631013	36274	2	1	C	29300	-2040	2810	2860	941	832	700	813	oil + mud	Beaverhill Lake
5W0631933070000	570921	35637	6	2	C	32200	-2210	3000	3020	1071	946	801	793	mud + cond.	Beaverhill Lake
5W0652023100000	790117	36737	5	1	A	31400	-2280	3040	3050	925	798	657	768	water + cond. + mud	Elk Point
5W0521418080000	810405	34796	6	1	B	34400	-2530	3500	3530	970	842	687	961	water + cond.	Elk Point
5W0651801100000	610204	36633	14	1	B	29400	-2130	2940	2950	864	752	619	803	cond.	Elk Point
5W0661411120000	590226	36392	9	1	B	26000	-1800	2970	2970	857	748	632	1160	water	Elk Point
5W0661832040000	641204	35620	3	1	B	29300	-2100	2870	2880	879	772	640	765	water + mud	Elk Point
5W0662109100000	641125	35619	6	1	B	32100	-2360	3090	3100	918	786	642	741	water + mud	Elk Point
5W0682114160000	850901	37007	2	1	B	30600	-2220	2930	2930	900	779	642	709	oil + cond. + water	Elk Point
5W0511727100000	580520	34920	10	1	C	38400	-2910	3900	3920	1106	952	775	1000	-	Elk Point
5W0611517150000	740119	35657	2	1	C	30100	-2160	3010	3020	908	790	655	862	-	Elk Point
5W0621916040000	590420	35775	6	1	C	32600	-2380	3250	3260	937	815	669	874	water	Elk Point
5W0632028020000	601230	36569	8	1	C	32600	-2400	3200	3200	923	795	649	787	water	Elk Point
5W0641805050000	570914	36626	10	1	C	31000	-2230	3030	3030	928	809	669	793	water + cond. + oil	Elk Point
5W0642401120000	611027	36683	3	1	C	36100	-2730	3580	3600	947	808	646	861	mud + oil + water	Elk Point
5W0651522020000	590321	36729	3 A1	C	27100	-1930	2910	2920	2920	832	726	604	993	water	Elk Point
5W0652304040000	641116	36795	2	1	C	34800	-2620	3400	3410	926	791	634	780	water + oil + mud + cond.	Elk Point
5W0671530100000	650221	35616	2	1	C	26800	-1860	2820	2820	870	767	646	956	water	Elk Point
5W0671834040000	630219	35540	2	1	C	28700	-2050	2810	2830	870	763	634	775	water	Elk Point
5W0692611060000	830821	36926	1	1	C	34900	-2610	3310	3350	945	811	654	702	water + mud	Elk Point
5W0571512010000	760404	35312	5	1	C	31200	-2280	3210	3220	906	778	638	937	water	Cambrian
5W0681709100000	650322	35757	5	1	C	28500	-2070	2970	3010	839	723	595	907	water + mud	Cambrian
5W0621818020000	590320	36561	10	1	C	32500	-2390	3280	3290	924	796	649	880	water + mud + oil + cond.	Cambrian

APPENDIX C: HYDROCHEMICAL DATA

All ion concentrations are measured in mg/l. The calculated sodium concentration (Na_c) was derived by charge balance calculation. See Chapter 3 for the equations to calculate $\text{Ca}_{\text{excess}}$ and $\text{Na}_{\text{deficit}}$ values. The Na/Cl ratios were calculated with the respective molar concentrations of sodium and chloride.

DLS	ID	#	elev	dtop	dbot	TDS	Cl	Na	Na _c	K	pH	SO ₄	Mg	Ca	HCO ₃	Ca _{ex}	Na _{cl}	Na/Cl	Aquifer
0635250306000	121463	1	866	1122	1137	1855	698	620	623	4	8.4	26	3	16	488	0	-10	1.375	Brazeau-B. River
0605192314000	152209	1	994	1218	1233	2670	1300	1051	1048	4	8.4	22	2	13	573	-1	-14	1.244	Brazeau-B. River
0565252007000	89469	2	1290	2028	2048	2860	1436	1081	1069	20	8.2	25	1	54	535	1	-12	1.148	Brazeau-B. River
0565232102000	169597	3	1093	1764	1797	3289	1645	1218	1217	2	6.7	115	8	63	488	1	-13	1.141	Brazeau-B. River
0575221403000	90858	3	1063	1576	1588	4886	2660	1905	1886	14	7.8	95	13	114	742	3	-18	1.094	Brazeau-B. River
0575221403000	90858	2	1063	1576	1588	4886	2530	1815	1794	20	8.2	103	13	83	625	1	-17	1.093	Brazeau-B. River
0575221403000	90858	5	1063	1576	1588	5225	2700	1913	1894	11	7.8	103	10	120	683	3	-17	1.082	Brazeau-B. River
0575221403000	90858	4	1063	1576	1588	5236	2700	1903	1885	12	7.9	119	4	128	644	4	-17	1.079	Brazeau-B. River
0575221403000	90858	7	1063	1576	1588	5151	2690	1884	1867	10	7.8	78	11	119	659	3	-17	1.077	Brazeau-B. River
0575221403000	90858	8	1063	1576	1588	5170	2760	1900	1880	14	7.8	27	5	124	630	3	-16	1.070	Brazeau-B. River
0555183502000	140021	2	1069	1511	1517	6749	3800	2568	2559	15	7.9	66	15	68	473	-1	-15	1.050	Brazeau-B. River
0535171506000	83819	1	912	1402	1427	5391	3063	2058	2050	12	7.5	61	7	52	305	-1	-15	1.038	Brazeau-B. River
0465163312000	64896	1	1259	2072	2094	6925	3910	2481	2472	14	7.8	80	17	207	488	6	-13	0.975	Brazeau-B. River
0585193411000	177298	1	907	1232	1264	3070	1753	1002	982	35	8.3	72	14	166	127	6	0	0.863	Brazeau-B. River
0545142016000	85094	10	849	1166	1169	8880	5166	3314	2892	29	7.0	0	17	363	20	13	-1	0.863	Brazeau-B. River
0545200808000	113854	1059	1757	1760	7888	4336	2732	2302	2427	71	5.6	20	6	403	320	16	-1	0.863	Brazeau-B. River
0455142904000	150898	3	1140	1879	1892	7310	3180	2593	2330	7.8	274	36	36	238	1064				Brazeau-B. River
0455162710020	63192	1	1244	2235	2239	7107	4120	2593	2292	7.1	22	13	15	175	364				Brazeau-B. River
0455162710020	63192	5	1244	2235	2239	6441	3800	2292	2292	7.1	22	13	15	208	214				Brazeau-B. River
0475151601000	67723	1	1265	2153	2161	3400	1873	1195	1195	8.1	13	36	4	52	244				Brazeau-B. River
0475152605000	67744	1	1183	n/a	n/a	2408	1027	951	951	8.4	6	6	4	17	745				Brazeau-B. River
0505211307000	79053	2	1057	2065	2076	4471	2050	1670	1670	8.5	288	6	6	71	756				Brazeau-B. River
0515173107000	81243	1	957	1525	1540	3776	2184	1423	1423	8.1	38	3	3	54	150				Brazeau-B. River
0525183610000	82715	2	903	1442	1455	2940	1268	1138	1138	9.2	224	2	2	12	566				Brazeau-B. River
0535181406000	83872	1	973	1582	1591	10420	6256	3900	3900	8.2	0	15	15	147	102				Brazeau-B. River
0545192111000	85247	5	1008	1577	1582	10363	5960	3850	3850	8.2	5	27	27	192	665				Brazeau-B. River
0545220210000	85278	5	1061	1776	1785	5639	3014	2075	2075	7.5	25	1	1	152	742				Brazeau-B. River
0545220210000	85278	6	1061	1776	1785	4234	2269	1529	1529	7.5	20	1	1	140	535				Brazeau-B. River
0555182606000	140019	1	1051	1467	1494	5571	3070	2155	2155	7.5	11	5	5	44	580				Brazeau-B. River
0555200808000	140024	1	1189	1780	1801	2512	1210	957	957	9.0	172	1	1	21	210				Brazeau-B. River
0555200808000	140024	2	1189	1780	1801	2524	1270	970	970	8.8	94	1	1	23	263				Brazeau-B. River
0555200808000	140024	4	1189	1780	1801	2440	1240	937	937	8.8	68	1	1	25	268				Brazeau-B. River
0555200914000	140025	8	1224	1794	1804	2744	1553	1061	1061	8.1	11	1	1	21	197				Brazeau-B. River
0555200914000	140025	9	1224	1794	1804	2391	1129	885	885	8.0	251	1	1	32	189				Brazeau-B. River
0555200914000	140025	10	1224	1794	1804	2517	1199	936	936	7.8	263	1	1	30	180				Brazeau-B. River
0555230101000	114964	1208	1905	1929	2990	1400	1080	1080	1080	7.7	25	2	2	61	415				Brazeau-B. River
0555230101000	114965	1208	1905	1929	2995	1350	1090	1090	1090	7.6	42	3	3	58	442				Brazeau-B. River

DLS	ID	#	elev	dtop	dbot	TDS	Cl	Na	Na _c	K	pH	SO ₄	Mg	Ca	HCO ₃	Ca _{ex}	Na _{cl}	Na/Cl	Aquifer
05552301010000	114969	1	1208	1905	1929	2950	875	1010			7.7	537	4	48	458				Brazeau-B. River
05552733090000	87512	1	1237	2157	2183	3383	1250	1257			7.7	118	2	97	1340				Brazeau-B. River
05651628070000	151987	2	971	1283	1293	5441	3120	2071			8.1	15	3	68	326				Brazeau-B. River
05652224090000	115882		895	1313	1329	1870	800	604			7.6	175	19	42	203				Brazeau-B. River
05652308070000	115895		1095	1737	1764	2726	908	955			7.6	148	3	19	683				Brazeau-B. River
05751904100000	90808	1	1224	1647	1662	4368	2520	1669			8.0	10	3	48	240				Brazeau-B. River
05752214030000	90858	12	1063	1576	1588	4578	2490	1670			7.8	46	3	128	490				Brazeau-B. River
05752214030000	90858	15	1063	1576	1588	4788	2640	1696			7.8	19	4	181	504				Brazeau-B. River
06060517100000	162554	1	1180	1874	1883	3134	1020	1164			8.6	292	10	60	1171				Brazeau-B. River
06151922120000	94962	2	920	1103	1108	2298	910	897			8.9	160	2	10	500				Brazeau-B. River
06252011120000	95927	1	841	967	975	1703	707	677			8.5	5	2	10	590				Brazeau-B. River
06252011202000	95928	1	844	909	910	1706	686	679			8.2	79	0	2	526				Brazeau-B. River
06452024100000	98573	6	789	778	780	1821	564	725			8.4	63	3	12	900				Brazeau-B. River
06660407110000	102429	7	798	1263	1278	7609	3212	3037	3027	16	8.0	51	9	26	2591	-2	-54	1.453	Cardium
06352522100000	97272	1	863	1393	1398	10582	4482	4184	4138	29	8.2	103	34	37	3467	-3	-72	1.433	Cardium
06352428030000	97244	5	906	1396	1437	9906	4277	3887	3871	12	8.4	25	7	102	3245	1	-65	1.396	Cardium
06660511110000	102439	5	903	1381	1396	7076	3151	2813	2803	16	8.1	29	6	31	2129	-2	-46	1.372	Cardium
06560222060000	101065	1	789	1240	1265	8977	4050	3573	3548	4	8.6	2	11	32	2603	-3	-56	1.351	Cardium
06152636060000	95040	4	1094	1820	1836	9369	4304	3720	3712	13	7.9	43	2	44	2554	-2	-57	1.330	Cardium
06352428030000	97244	3	906	1396	1437	9701	4574	3817	3809	13	8.1	24	1	75	2461	-1	-55	1.284	Cardium
06352403060000	97234	1	876	1429	1442	9873	4730	3910	3897	21	7.6	4	11	38	2401	-3	-55	1.270	Cardium
06452318060000	98614	1	860	1265	1285	9035	4650	3521	3507	23	8.0	86	15	48	1454	-3	-40	1.163	Cardium
06452317050000	98611	2	818	1230	1234	8073	4078	3125	3067	20	8.4	104	22	51	1287	-2	-35	1.160	Cardium
05951813060000	92856	1	944	1490	1504	19325	10540	7416	7399	27	7.8	37	43	180	2257	-2	-67	1.083	Cardium
05951802080000	92847	1	961	1539	1544	17884	10200	6962	6889	124	7.5	25	20	76	1222	-7	-53	1.041	Cardium
05651633060000	89380	1	977	1595	1612	17039	9650	6535	6479	55	8.8	119	36	130	1098	-4	-48	1.035	Cardium
06252414120000	96062	1	1003	1598	1603	14346	8210	5558	5496	105	7.8	33	21	75	913	-5	-40	1.032	Cardium
05751606100000	116331		1070	1673	1679	24916	13600	9420	8906	44	7.9	38	107	227	1480	-3	-81	1.010	Cardium
05751723100000	116384		1122	1704	1711	22703	12100	8670	7848	51	8.0	54	105	292	1430	2	-84	1.000	Cardium
05551536160000	87392	3	936	1553	1558	20269	11790	7559	7541	29	7.3	19	109	260	1083	0	-43	0.986	Cardium
05551417160000	87368	1	865	1495	1506	15723	8960	6057			8.3	118	34	90	915				Cardium
05651628070000	151987	1	971	1596	1606	28179	15580	10682			7.3	31	74	358	2957				Cardium
05751506060000	90767	1	1091	1685	1688	24338	14400	9224			8.0	30	62	243	582				Cardium
05751615110000	116341		1117	1701	1706	20687	11300	7880			8.1	2	69	275	1050				Cardium
05751736020000	161148		1130	1692	1690	22613	12400	8730			7.8	2	42	133	1270				Cardium
05751736020000	161991		1130	1692	1698	23050	12700	8690			7.8	2	43	181	1400				Cardium
05951825160000	118008		928	1447	1462	18674	10000	7020			8.0	11	50	168	1390				Cardium
05951825160000	118011		928	1447	1462	19646	10800	7160			7.8	16	50	163	1420				Cardium

DLS	ID	#	elev	dtop	dbot	TDS	Cl	Na	Na _c	K	pH	SO ₄	Mg	Ca	HCO ₃	Ca _{ex}	Na _{cl}	Na/Cl	Aquifer
0595182516000	118015		928	1447	1462	17966	9590	6790			7.6	11	49	162	1330				Cardium
0595183602000	162470	2	921	1440	1444	20610	11700	7893			7.5	21	35	187	1510				Cardium
0605201716000	118819		952	1558	1568	11094	5400	4180			8.1	661	10	90	697				Cardium
0605242703000	118944		1124	1892	1907	16007	7750	6060			7.7	33	26	73	2030				Cardium
0605242703000	118945		1124	1892	1907	15193	7750	5400			8.1	38	27	76	1880				Cardium
0605242703000	118946		1124	1892	1907	14969	7500	5270			7.8	57	26	91	2000				Cardium
0605242703000	118947		1124	1892	1907	15887	8000	5660			7.8	49	26	80	2040				Cardium
0615251607000	95031	1	1141	1899	1913	10734	5480	4178			8.1	82	25	58	1854				Cardium
0625253010000	96076	3	929	1535	1554	8885	3958	3460			7.9	6	10	26	2492				Cardium
0625260909000	96081	2	949	1627	1632	10330	4510	4097			8.2	25	21	44	3320				Cardium
0625262110000	96088	1	948	1597	1601	7741	3178	3078			8.3	53	17	32	2814				Cardium
0635242910000	97242	4	848	1337	1346	9902	4780	3328			7.7	20	132	413	2500				Cardium
0635242910000	97245	1	888	1372	1393	9085	4228	3601			7.6	25	6	42	2406				Cardium
0645231311000	98607	2	857	1242	1243	11343	6200	4360			7.2	38	26	94	1270				Cardium
0676043210000	103599	7	693	963	978	7555	3320	3015			8.4	12	9	24	2270				Cardium
0606020806000	93882	1	1267	2742	2750	6423	2595	2340	2240	170	7.5	8	16	229	2511	9	-35	1.331	Dunvegan
0655212208000	122906	0	801	1295	1315	12890	5270	4500	4482	20	8.1	205	16	63	2816	-2	-67	1.306	Dunvegan
0626013411000	96111	5	1059	2097	2102	7028	3230	2663	2637	20	8.8	612	27	28	915	-2	-37	1.259	Dunvegan
0655240110000	101023	1	860	1486	1492	7551	3785	2844	2825	24	8.4	218	43	73	1183	0	-31	1.151	Dunvegan
0645241106000	122252	0	877	1602	1608	10617	5276	3660	3673	332	7.0	173	10	37	1129	-4	-32	1.073	Dunvegan
0636010110000	97310	2	1012	1986	1996	10777	5400	4245			8.3	20	13	44	2085				Dunvegan
0655211413000	122863	0	794	1276	1292	12690	5354	4300			8.3	165	18	43	2790				Dunvegan
0655232010020	101017	1	786	1362	1368	12028	6415	4724			8.5	66	10	37	1548				Dunvegan
0655252702000	102411	1	736	1250	1271	10615	5700	4156			7.5	20	13	43	1390				Dunvegan
0685221014000	163677	14	669	950	961	3733	1800	1429			8.3	200	5	28	551				Dunvegan
0685232511000	104531	1	725	975	1012	6939	3550	2702			8.4	102	11	36	1010				Dunvegan
0686010911000	104551	1	711	1194	1202	11112	5980	4355			8.4	71	14	32	1270				Dunvegan
0686010911000	104551	2	711	1204	1215	9310	5020	3660			8.6	26	8	26	1040				Dunvegan
0686012311000	104553	1	680	1119	1149	8032	4377	3107			8.4	46	11	57	854				Dunvegan
0646032710000	177719	2	858	2043	2046	11100	5250	4411	4351	23	8.5	113	7	24	2513	-4	-62	1.278	Viking
0625251805000	96072	4	923	2079	2094	11371	5575	4467	4455	20	7.5	25	24	50	2501	-3	-59	1.232	Viking
0615272610000	95043	4	1167	2451	2452	10924	5410	4297	4273	42	7.7	4	11	59	2324	-3	-55	1.218	Viking
0666040711000	102429	2	798	1937	1958	12705	6380	5026	5017	16	7.7	8	11	39	2523	-5	-64	1.213	Viking
0666040711000	102429	1	798	1937	1958	12523	6300	4944	4933	19	8.0	10	10	48	2482	-4	-62	1.207	Viking
0655201410000	100975	1	767	1390	1400	12120	6101	4783	4723	33	8.6	15	10	47	2260	-4	-58	1.194	Viking
0655221816000	123504	0	711	1367	1373	9739	4700	3654	3458	14	7.4	49	10	36	1208	-3	-37	1.135	Viking
0645241710000	98634	2	882	1786	1806	12824	6837	5037	4972	34	8.5	9	16	42	1679	-5	-51	1.121	Viking
0635201910000	97191	2	767	1567	1593	16504	8900	6482	6470	21	7.6	6	20	49	2128	-7	-66	1.121	Viking

DLS	ID	#	elev	dtop	dbot	TDS	Cl	Na	Na _c	K	pH	SO ₄	Mg	Ca	HCO ₃	Ca _{ex}	Na _{cl}	Na/Cl	Aquifer
0635141614000	141087	2	966	1484	1490	14983	8100	5840	5832	13	7.9	35	24	72	1854	-5	-58	1.110	Viking
0605152307000	93710	2	799	1489	1512	10735	5704	4196	4143	37	8.5	185	10	28	1000	-5	-40	1.105	Viking
0685103512000	137913	0	723	1907	1933	17426	8899	5900	6332	37	7.7	25	32	212	2321	1	-60	1.097	Viking
0665181707000	163487	1	799	1290	1300	11530	6333	4513	4501	20	7.8	40	1	54	1197	-4	-43	1.096	Viking
0665181707000	163487	2	799	1290	1300	11366	6223	4433	4421	20	7.8	17	5	67	1263	-3	-42	1.096	Viking
0655192907000	100962	2	786	1370	1371	12919	7155	5045	5030	26	8.1	5	14	56	1310	-5	-46	1.084	Viking
0686063010000	104611	1	699	1686	1707	16731	9220	6507	6467	69	7.6	27	18	97	1753	-5	-58	1.081	Viking
0685103512000	137912	0	723	1907	1933	18212	9252	6300	6436	35	7.2	16	48	279	2282	4	-56	1.073	Viking
0615153608000	94872	1	915	1503	1527	18120	10120	7030	7014	27	7.6	29	32	96	1655	-6	-60	1.069	Viking
0655192907000	100962	1	786	1370	1371	11250	6356	4393	4358	41	8.6	5	13	40	872	-5	-36	1.057	Viking
0605140309000	93672	2	787	1467	1471	19481	10985	7520	7502	30	8.1	71	21	144	1505	-4	-61	1.053	Viking
0615171602000	94909	2	864	1615	1635	23228	13180	8975	8916	100	8.3	60	64	108	1710	-9	-69	1.043	Viking
0595142112000	1621115	0	967	1682	1696	23070	12500	8365	8452	33	7.8	138	85	180	1769	-4	-65	1.043	Viking
0615161706000	94892	1	886	1600	1618	24594	14160	9503	9487	27	7.7	8	42	146	1495	-8	-70	1.033	Viking
0595140606000	92776	2	1011	1777	1812	20179	11550	7756	7738	30	7.5	16	38	164	1344	-4	-57	1.033	Viking
0615161706000	94892	2	886	1600	1618	24184	14040	9407	9389	29	7.9	14	38	83	1226	-11	-69	1.031	Viking
0595203510000	92907	2	1001	2019	2030	25050	14600	9437	9418	32	7.6	33	90	292	1216	-1	-57	0.995	Viking
0675153306020	103454	1	916	1209	1215	25186	15020	9568	9543	42	7.1	12	66	236	577	-4	-52	0.980	Viking
0595183405000	117115	0	999	1963	1977	25003	14100	9810			7.2	17	27	178	811				Viking
0595181013000	117966	0	1073	2028	2037	10923	4500	3450			7.8	2000	12	275	456				Viking
0595182115000	117994	0	923	1482	2235	22826	13800	7950			7.8	340	73	274	311				Viking
0615151404000	94861	1	831	1494	1501	19545	10789	7572			7.5	16	43	113	2100				Viking
0615181011000	94921	2	900	1734	1740	23095	13000	8958			8.3	27	35	127	1928				Viking
0615192410000	94963	1	936	1772	1782	19875	11160	7678			7.5	28	33	135	1710				Viking
0615240310000	95025	1	1130	2311	2344	15105	7750	5922			8.8	87	28	54	2450				Viking
0615242613000	161605	0	1034	2133	2184	10062	3600	3670			8.1	729	17	40	1970				Viking
0625142810000	95790	3	869	1420	1429	16787	9040	6542			7.8	10	33	80	2200				Viking
0625152110000	95798	4	1016	1616	1640	13352	7003	5218			8.2	4	22	68	2109				Viking
0625252607000	96075	12	947	2032	2043	12534	6200	4967			8.0	8	20	24	2674				Viking
0625260909000	96081	3	949	2142	2158	12595	5825	4996			7.9	22	12	54	3430				Viking
0625260909000	96081	4	949	2142	2158	12581	5825	4984			8.1	20	14	57	3420				Viking
0635142010000	97062	1	1003	1514	1531	14767	7730	5770			7.6	56	21	74	2269				Viking
0635161904000	121100	0	1044	1648	1653	15255	8160	4960			8.0	307	23	49	1720				Viking
0635162612000	121104	0	1035	1604	1622	13683	6830	5190			7.5	21	16	47	1550				Viking
0635202802000	97195	1	787	1572	1584	23527	13021	9020			7.5	15	53	218	2440				Viking
0645160908000	161003	0	922	1473	1480	16712	8250	6410			7.6	8	21	57	1930				Viking
0655191710000	100955	1	743	1353	1359	11936	6579	4625			8.4	49	15	78	1140				Viking
0655200510020	100973	1	763	1430	1452	13826	7000	5451			7.9	91	15	40	2500				Viking

DLS	ID	#	elev	dtop	dbot	TDS	Cl	Na	Na _c	K	pH	SO ₄	Mg	Ca	HCO ₃	Ca _{ex}	Na _{cl}	Na/Cl	Aquifer
0655211314000	122861	0	794	1458	1462	12492	6480	4600			7.7	99	14	18	1264				Viking
0655212006000	100987	4	748	1433	1452	12334	5732	4905			7.5	12	12	41	3321				Viking
0665161216000	102285	2	881	1284	1295	16979	8758	6604			7.5	23	30	119	2938				Viking
0665181004000	102312	1	814	1314	1329	11521	6283	4491			7.4	22	16	55	1324				Viking
0665181810000	102314	1	810	1305	1319	12544	6910	4904			7.7	16	21	40	1328				Viking
0665193506000	102328	3	760	1243	1251	14032	7905	5436			0.0	22	34	64	1160				Viking
0665200102000	163493	1	769	1342	1346	12707	6980	4974			7.9	21	13	35	1310				Viking
0665210312000	102338	1	807	1441	1443	9865	4748	3886			8.2	22	14	49	2332				Viking
0665210312000	102338	2	807	1441	1443	10729	5410	4212			8.0	22	11	57	2068				Viking
0665222607000	102379	1	707	1316	1320	10371	4337	4097			7.9	6	20	76	3733				Viking
0665233510000	102391	3	812	1428	1433	19234	10827	7404			8.4	271	25	126	1132				Viking
0666041512000	170259	1	711	1807	1814	11504	5810	4562			8.2	20	13	17	2120				Viking
0666052610000	102440	1	794	1899	1908	18552	10300	7221			7.8	15	29	88	1830				Viking
0666052810000	102441	5	839	1975	1980	17220	9530	6713			7.0	28	26	73	1730				Viking
0685262901000	104546	1	671	1299	1311	24097	14207	9182			8.0	7	85	181	885				Viking
0695220201000	105434	1	657	1073	1087	28055	16283	10647			7.5	30	126	226	1513				Viking
0695230606000	105514	1	728	1205	1216	19344	11150	7431			7.6	3	66	109	1190				Viking
0686112707000	137938	0	757	2208	2228	14346	5880	4784	4605	31	7.8	26	46	249	3450	6	-63	1.250	Upper Mannville
0645161811000	121917	0	912	1488	1494	16794	8780	5745	6018	430	7.8	2	16	52	1769	-7	-49	1.057	Upper Mannville
0645161811000	121916	0	912	1488	1494	17071	8500	5929	5717	641	7.8	15	39	56	1891	-6	-43	1.037	Upper Mannville
0635171704000	161762	0	966	1624	1908	21607	12447	7800	8140	62	8.1	103	51	183	961	-4	-53	1.008	Upper Mannville
0675192107000	123963	0	752	1249	1264	20835	12020	7498	7854	39	7.4	132	57	186	903	-3	-51	1.008	Upper Mannville
0696072410000	105575	3	676	1799	1807	23193	13430	8718	8885	55	7.7	4	50	344	1316	3	-53	0.997	Upper Mannville
0675192107000	123956	0	752	1249	1264	19505	10900	7317	7035	35	8.0	23	86	192	952	-2	-42	0.995	Upper Mannville
0675192107000	123958	0	752	1293	1307	27161	15450	9660	9950	54	7.9	64	109	360	1464	2	-59	0.993	Upper Mannville
0675192107000	123961	0	752	1293	1307	27255	15600	9476	9997	63	7.5	41	137	376	1562	2	-58	0.988	Upper Mannville
0675192107000	123957	0	752	1293	1307	27203	15550	9568	9935	63	7.2	51	143	364	1464	2	-56	0.985	Upper Mannville
0675192107000	123960	0	752	1249	1264	19784	11600	7475	7310	35	7.5	35	69	192	378	-3	-37	0.972	Upper Mannville
0565171107000	115742	0	916	2239	2253	50300	30000	18200	18749	192	8.1	8	121	681	1098	2	-90	0.964	Upper Mannville
0685240715000	161706	0	753	1475	1480	36913	21480	13241	13008	102	7.1	13	243	721	1113	13	-46	0.934	Upper Mannville
0525192904000	112389	0	1000	2656	2665	31871	18200	11000			6.9	2	90	640	1930				Upper Mannville
0555141712000	114626	0	870	2080	2098	11575	6770	4250			6.5	5	27	141	320				Upper Mannville
0565150706000	115661	0	927	2159	2162	30255	15100	10300			7.8	29	43	126	4120				Upper Mannville
0575182102000	116414	0	1285	2565	2575	63292	33200	23803			8.1	337	233	256	5002				Upper Mannville
0605152704000	118636	0	794	1505	1523	14480	7970	5200			7.3	128	24	80	1010				Upper Mannville
0635130707000	120988	0	928	1713	1725	61460	36143	22862			8.0	291	58	827	1179				Upper Mannville
0645161907000	161335	0	917	1479	1489	19671	9770	7540			7.9	7	24	72	2230				Upper Mannville
0645161907000	161340	0	917	1477	1482	16575	8220	6190			8.1	14	23	64	2040				Upper Mannville

DLS	ID	#	elev	dtop	dbot	TDS	Cl	Na	Na _c	K	pH	SO ₄	Mg	Ca	HCO ₃	Ca _{ex}	Na _d	Na/Cl	Aquifer	
0645161907000	161341	0	917	1477	1482	18339	9250	6650			8.2	4	32	80	2300				Upper Mannville	
0645161907000	161342	0	917	1477	1482	18368	9250	6760			7.7	9	29	88	2210				Upper Mannville	
0645212001000	122158	0	798	1563	1599	13631	6500	4830			8.3	202	27	79	1970				Upper Mannville	
0645212115000	122164	0	782	1558	1563	11291	4970	4300			8.0	46	9	24	1920				Upper Mannville	
0645212115000	122855	0	761	1480	1487	10838	4270	3720			8.0	46	11	24	2750				Upper Mannville	
0655230610000	122955	0	852	1661	1670	9604	4300	3220			8.3	12	8	24	1970				Upper Mannville	
0665140812000	123297	0	1143	1510	1523	14458	7000	5500			8.0	888	32	71	924				Upper Mannville	
0665140812000	123298	0	1143	1510	1523	19206	10500	7430			7.5	5	36	95	1100				Upper Mannville	
0665140812000	123299	0	1143	1510	1523	19970	11000	7630			7.6	3	40	89	1170				Upper Mannville	
0685240710000	104534	1	747	1622	1626	33446	20025	12268			7.9	8	109	685	715				Upper Mannville	
0686021511000	104557	3	694	1650	1667	30085	18150	11591			7.1	26	46	164	220				Upper Mannville	
0686112707000	137939	0	757	2208	2228	14426	5780	4738			7.5	12	32	334	3428				Upper Mannville	
0686130910000	138007	0	926	2633	2643	15885	7500	5660			7.2	86	66	77	2280				Upper Mannville	
0696091910000	105601	2	703	1908	1918	29930	18030	10041			7.9	2	284	1213	732				Upper Mannville	
0625182001000	120220	0	872	1890	1899	57251	32000	21142	21709		125	7.4	831	98	218	2837	-23	-170	1.046	Lower Mannville
0675230914000	161941	0	765	1768	1795	54388	32000	19683	20953		102	7.1	23	95	332	2153	-17	-137	1.010	Lower Mannville
0565140412000	115622	0	1208	2098	2104	44872	25800	15950	16930		153	8.0	78	131	420	2340	-6	-108	1.006	Lower Mannville
0646012007000	98652	8	865	2405	2409	62327	37200	24123	24022		170	7.2	30	136	210	1279	-29	-145	0.986	Lower Mannville
0645153203000	98449	1	990	1695	1709	62034	37300	24181	24077		175	6.3	19	63	136	683	-33	-145	0.995	Lower Mannville
0646012007000	98652	9	865	2405	2409	63098	37600	24383	24258		210	7.2	20	140	250	1435	-27	-146	0.995	Lower Mannville
0665222306000	102376	3	734	1695	1712	69900	41500	26770	26730		67	7.8	25	146	521	1908	-18	-159	0.993	Lower Mannville
0636011408000	135630	0	884	2476	2486	53674	30600	20800	19625		134	7.0	432	124	439	1040	-11	-113	0.989	Lower Mannville
0686031111000	104561	3	715	1982	1990	61952	37000	23673	23611		103	7.0	5	241	345	1400	-22	-132	0.984	Lower Mannville
0656021107000	101060	9	850	2340	2351	60545	36100	23090	23012		131	8.0	6	194	440	1454	-16	-128	0.983	Lower Mannville
0656022806000	152869	1	784	2257	2264	62383	37000	23952	23577		635	6.9	263	170	320	1379	-23	-131	0.983	Lower Mannville
0656021107000	101060	8	850	2340	2351	59612	35600	22716	22640		128	8.0	2	182	460	1327	-15	-124	0.981	Lower Mannville
0615191603000	119571	0	914	2062	2235	82221	43000	30500	27296		1330	7.4	2500	220	1540	3130	31	-147	0.979	Lower Mannville
0656021107000	101060	10	850	2340	2351	61043	36500	23202	23112		151	8.0	10	219	476	1293	-15	-122	0.976	Lower Mannville
0685203605000	104432	1	755	1460	1492	49153	29050	18455	18393		104	7.1	8	160	637	1714	1	-97	0.976	Lower Mannville
0635251014000	97260	1	913	2368	2391	62504	37350	23683	23645		80	6.8	4	194	591	1366	-10	-125	0.976	Lower Mannville
0645252106000	177710	2	848	2076	2088	39291	23412	14863	14803		100	6.8	4	120	407	987	-5	-78	0.975	Lower Mannville
0635252210000	97272	4	863	2296	2318	59095	35400	22431	22382		82	8.0	58	202	492	1042	-13	-117	0.975	Lower Mannville
0685240903000	124538	0	755	1695	1702	28612	16900	9670	10669		212	6.9	746	190	328	564	-2	-55	0.973	Lower Mannville
0696041212000	105542	2	658	1912	1920	46668	27750	17551	17507		73	7.0	72	214	472	1238	-6	-90	0.973	Lower Mannville
0645252106000	177710	3	848	2076	2088	40017	23770	15055	14996		100	6.9	12	79	554	1113	2	-77	0.973	Lower Mannville
0675141601000	103438	1	1036	1550	1574	40906	24300	15436	15316		204	7.9	156	135	426	921	-5	-78	0.972	Lower Mannville
0666042912000	136541	0	818	2348	2357	65350	39350	23586	24764		227	6.6	62	155	721	1249	-6	-125	0.970	Lower Mannville
0646022711000	162880	1	885	2434	2447	61170	36500	23147	22917		380	7.1	86	194	601	1305	-9	-114	0.968	Lower Mannville

DLS	ID	#	elev	dtop	dbot	TDS	Cl	Na	Na _c	K	pH	SO ₄	Mg	Ca	HCO ₃	Ca _{ex}	Na _{ar}	Na/Cl	Aquifer
0665253606000	102413	2	748	1789	1794	51969	30750	19575	19276	507	8.3	84	170	601	1604	-3	-95	0.967	Lower Mannville
0646033510000	141248	5	860	2454	2465	71117	42700	26850	26766	141	6.6	4	211	773	1176	-7	-131	0.967	Lower Mannville
0686053610000	137522	0	665	1991	1997	62964	38700	22080	24203	141	7.5	7	199	741	1096	-4	-117	0.964	Lower Mannville
0656032810000	177777	1	846	2404	2417	75615	45500	28527	28446	136	7.2	64	243	801	976	-8	-137	0.964	Lower Mannville
0665250112000	162599	0	769	1944	1947	86719	52900	31050	32989	528	7.3	77	243	857	1064	-13	-155	0.962	Lower Mannville
0685220409000	141836	2	679	1480	1487	46996	28000	17531	17461	117	6.5	31	194	641	1220	2	-82	0.962	Lower Mannville
0655160202000	163335	0	1034	1743	1752	66819	41200	23700	25601	253	7.5	4	233	641	549	-12	-117	0.958	Lower Mannville
0636012106000	162766	1	978	2613	2624	67491	40500	25245	25152	156	8.3	134	267	841	1025	-1	-114	0.958	Lower Mannville
0666041311000	102431	1	732	2289	-1000	76564	46390	28797	28789	11	7.9	12	304	801	549	-9	-130	0.957	Lower Mannville
0635141614000	141087	1	966	1736	1770	52514	31500	19617	19535	138	7.6	31	160	757	915	4	-88	0.956	Lower Mannville
0625243104000	96068	2	897	2352	2369	66206	39900	24747	24671	128	6.5	23	292	805	893	-2	-108	0.953	Lower Mannville
0656033110000	152870	2	810	2391	2435	75760	45500	28370	28670	508	6.9	128	267	961	1086	0	-120	0.951	Lower Mannville
0615152310000	94867	3	881	1763	1778	54817	32926	20449	20306	243	7.7	4	172	810	927	5	-87	0.951	Lower Mannville
0666041411000	153213	1	718	2274	2287	74319	44500	27523	27421	172	6.6	249	388	1041	1257	5	-116	0.950	Lower Mannville
0686041116000	104572	2	691	2049	2056	60285	36200	22340	22293	79	7.8	95	355	785	1037	1	-94	0.950	Lower Mannville
0545163210020	169474	1	890	2265	2275	34293	20400	12711	12559	258	7.2	92	104	586	813	8	-53	0.949	Lower Mannville
0646031306000	177717	1	889	2562	2571	74643	45000	27688	27586	172	6.6	35	413	985	1061	1	-111	0.945	Lower Mannville
0625181703000	120213	0	886	1936	1948	57997	35800	20400	21936	148	5.8	5	182	870	392	5	-88	0.945	Lower Mannville
0665153612000	102276	2	1028	1585	1606	41887	25100	15429	15350	133	7.1	16	219	681	900	7	-61	0.943	Lower Mannville
0605220101000	118884	0	1061	2581	2588	36545	21200	13700	12935	115	6.6	19	129	635	580	9	-50	0.941	Lower Mannville
0625182412000	120237	0	875	1896	1906	70149	43346	24000	26437	190	5.9	5	449	1002	1157	4	-102	0.940	Lower Mannville
0685261005000	104544	1	688	1660	1679	33938	20350	12468	12397	120	7.6	27	222	517	720	4	-47	0.939	Lower Mannville
0636021312020	152350	9	990	2686	2698	79582	48250	29455	29380	125	7.8	26	384	1201	580	9	-111	0.939	Lower Mannville
0645152710000	177702	2	1027	1785	1790	70473	42500	26036	25879	260	6.1	35	225	1250	834	17	-98	0.939	Lower Mannville
0645170608000	121931	0	817	1740	1753	64680	39500	23000	24049	259	7.5	4	217	1080	621	12	-91	0.939	Lower Mannville
0635180115000	97101	2	892	1847	1855	58079	35000	21317	21254	106	7.7	6	335	961	935	11	-78	0.936	Lower Mannville
0686070107000	104618	3	722	2306	2310	71424	43100	26215	26108	180	7.0	16	340	1277	968	18	-93	0.934	Lower Mannville
0636021312020	152350	12	990	2686	2698	82946	50000	30482	30228	430	6.2	74	425	1401	1147	17	-105	0.932	Lower Mannville
0656051205000	101082	2	841	2578	2584	90489	54600	33440	32979	781	6.7	148	335	1522	903	18	-114	0.931	Lower Mannville
0656051205000	101082	4	841	2578	2584	86125	52000	31799	31396	684	6.5	222	471	1249	781	7	-108	0.931	Lower Mannville
0575161007000	90776	1	1051	2301	2321	61696	37244	22636	22459	300	6.7	27	385	981	859	9	-76	0.930	Lower Mannville
0645180709000	121993	0	708	1755	1760	89862	53000	34100	31953	418	6.2	29	340	1500	476	19	-108	0.930	Lower Mannville
0645170608000	121932	0	817	1740	1753	65515	41000	22400	24666	238	7.4	4	204	1330	340	23	-81	0.928	Lower Mannville
0645191303000	141240	1	759	1732	1738	77457	46900	28213	28143	118	6.7	27	365	1578	759	29	-90	0.925	Lower Mannville
0636021312020	152350	11	990	2686	2698	81830	49500	29928	29685	410	6.2	37	425	1502	891	22	-94	0.925	Lower Mannville
0645181806000	98479	1	777	1729	1743	92281	56000	33650	33575	126	7.2	23	462	1802	700	30	-106	0.924	Lower Mannville
0645171309000	121941	0	940	1764	1767	64938	39420	22786	23625	156	6.7	8	466	1153	939	16	-74	0.924	Lower Mannville
0615192412000	119585	0	919	2040	2058	68366	39700	26100	23780	151	6.5	1	313	1350	702	25	-74	0.924	Lower Mannville

DLS	ID	#	elev	diop	dbot	TDS	Cl	Na	Na _c	K	pH	SO ₄	Mg	Ca	HCO ₃	Ca _{ex}	Na _{cl}	Na/Cl	Aquifer
0645181806000	98479	2	777	1728	1744	85698	51900	31133	31057	126	7.9	84	294	1966	654	43	-86	0.923	Lower Mannville
0665161602000	123366	0	831	1545	1559	81796	49800	29400	29727	581	6.9	48	388	1350	88	14	-88	0.920	Lower Mannville
0665221507000	102373	3	730	1691	1693	53408	31620	19051	18862	320	7.5	58	316	1409	1940	37	-56	0.920	Lower Mannville
0635202210000	97193	1	801	1829	1840	47945	28850	17300	17203	164	6.8	2	131	1273	791	33	-50	0.919	Lower Mannville
0616011103000	95045	1	1243	3110	3127	84226	50500	31061	30099	1635	7.0	76	401	1381	1640	15	-88	0.919	Lower Mannville
0615263606000	95040	2	1094	2704	2718	58748	35400	21133	21082	118	6.2	2	250	1493	956	37	-60	0.917	Lower Mannville
0625262014000	96086	1	1036	2572	2588	71220	43000	25938	25578	610	6.6	10	433	1329	1037	21	-73	0.917	Lower Mannville
0635193309000	97170	1	784	1774	1787	62676	37900	23024	22537	827	7.6	23	194	1241	598	22	-64	0.917	Lower Mannville
0635192612020	162755	3	794	1786	1799	55605	33500	20226	19912	531	7.4	62	208	1241	754	26	-56	0.917	Lower Mannville
0595162910000	92823	1	1007	2074	2082	75765	45935	27439	27264	296	6.6	3	209	1895	577	46	-75	0.915	Lower Mannville
0626013411000	96111	4	1059	2725	2735	71302	43250	25725	25651	125	7.8	2	680	1201	903	14	-70	0.915	Lower Mannville
0655161113000	100916	4	1049	1749	1775	56449	34100	20338	20222	196	6.9	95	471	1085	773	17	-55	0.914	Lower Mannville
0656051205000	101082	3	841	2578	2584	76159	46100	27950	27289	1123	6.5	128	554	1073	720	5	-72	0.913	Lower Mannville
0686081106000	104634	1	811	2466	2469	85860	52000	30851	30492	609	6.0	16	748	1592	961	24	-69	0.904	Lower Mannville
0615262413000	95036	2	1156	2802	2812	64060	38800	22759	22681	130	6.5	14	289	1854	699	51	-48	0.901	Lower Mannville
0615263606000	95040	1	1094	2757	2767	69748	42400	24749	24678	118	6.2	2	552	1710	681	40	-48	0.897	Lower Mannville
0686070710000	104619	4	749	2363	2376	89300	54300	31636	31541	160	6.8	2	938	1914	1037	38	-59	0.896	Lower Mannville
0615161509000	94890	1	858	1808	1819	79343	48200	27843	27618	380	6.5	80	356	2600	537	79	-35	0.884	Lower Mannville
0646082506000	98707	1	1046	3141	3149	88241	53700	31241	29786	2471	7.1	12	391	2650	503	75	3	0.855	Lower Mannville
0676080706000	103643	19	868	2665	2682	93824	57400	31210	31061	250	6.7	21	1115	3680	810	123	37	0.834	Lower Mannville
0676080706000	103643	17	868	2665	2682	93663	57500	30492	30360	222	6.6	10	1113	4276	553	152	70	0.814	Lower Mannville
0676080706000	103643	18	868	2665	2682	94166	58000	29835	29687	249	6.5	21	1614	4356	692	156	112	0.789	Lower Mannville
0485181404000	71559	1	1138	3380	3390	42643	25100	14853			6.4	288	243	1441	1460				Lower Mannville
0525191612000	112368	0	602	2018	2028	48553	28500	16000			7.3	465	265	1740	961				Lower Mannville
0565170406000	115735	0	1013	2449	2468	16965	7600	5610			8.3	1572	78	175	1879				Lower Mannville
0575191507000	140392	1	1164	2518	2533	26298	15700	9310			6.7	70	187	701	671				Lower Mannville
0585153111000	91959	1	1035	2097	2100	45955	28000	15776			7.2	41	338	1642	321				Lower Mannville
0595243404000	92941	2	1132	2835	2844	63518	38480	22401			6.5	31	218	2083	620				Lower Mannville
0605223513000	93859	2	984	2401	2428	35587	21300	12826			8.0	12	316	660	961				Lower Mannville
0605232010000	93861	1	1028	2599	2609	68651	41500	24623			7.1	40	406	1639	900				Lower Mannville
0605233060000	93863	4	1072	2619	2625	67418	41000	23888			6.6	8	430	1826	540				Lower Mannville
0615183007000	94932	3	960	2054	2086	56717	34000	21102			8.2	15	143	941	1050				Lower Mannville
0615190403020	177502	1	974	2129	2139	41710	24991	15125			6.2	4	73	1102	844				Lower Mannville
0615212207000	95003	2	967	2251	2276	43298	25881	15914			7.4	6	217	754	1069				Lower Mannville
0615212910000	95007	1	951	2293	2305	54601	32900	19834			6.8	14	151	1229	760				Lower Mannville
0615243607000	95028	3	1046	2533	2541	68755	41600	25189			6.4	14	175	1477	610				Lower Mannville
0625152110000	95798	1	1016	1857	1885	48581	29225	18020			7.5	8	322	574	879				Lower Mannville
0625253010000	96076	1	929	2467	2480	69847	41900	26825			7.3	2	100	492	1074				Lower Mannville

DLS	ID	#	elev	dtop	dbot	TDS	Cl	Na	Na _c	K	pH	SO ₄	Mg	Ca	HCO ₃	Ca _{ex}	Na _{df}	Na/Cl	Aquifer
0625262206000	96089	6	930	2532	2537	56039	33600	20800			6.8	199	224	833	780				Lower Mannville
0626023214000	96121	2	1052	2830	2845	96639	59000	34622			6.4	10	553	2341	230				Lower Mannville
0635151510000	97080	1	946	1740	1747	52498	31500	19614			6.6	7	190	715	960				Lower Mannville
0635192110000	97139	1	786	1777	1818	58768	35300	21631			7.2	11	300	951	968				Lower Mannville
0635192212000	97148	4	787	1806	1810	54857	33000	20214			7.4	5	185	1021	880				Lower Mannville
0635221411000	152344	2	853	2100	2103	56048	33800	20813			7.4	7	197	878	717				Lower Mannville
0635222312000	170061	2	841	1974	1978	36493	22000	13573			7.1	49	146	521	415				Lower Mannville
0635232706000	97229	2	852	2150	2173	59961	35700	23080			8.1	14	114	350	1430				Lower Mannville
0635243010000	97246	3	882	2271	2281	61941	37000	23621			6.2	2	129	545	1311				Lower Mannville
0635251204000	97262	1	892	2351	2370	52100	30995	19706			6.9	4	91	640	1352				Lower Mannville
0635260511000	97286	3	997	2530	2544	52022	31000	19675			7.6	132	120	577	1054				Lower Mannville
0635263510000	97305	1	936	2395	2402	65537	39250	25229			7.7	4	153	328	1165				Lower Mannville
0636010110000	97310	3	1012	2613	2635	84263	51000	31101			7.5	16	264	1528	720				Lower Mannville
0645143202000	98440	1	1076	1743	1747	54977	33140	20221			6.8	54	254	950	727				Lower Mannville
0645152510000	98448	1	1064	1747	1770	59779	36100	21938			6.6	23	218	1161	690				Lower Mannville
0645180402000	98467	2	791	1763	1769	52182	31250	19944			7.7	16	114	403	925				Lower Mannville
0645181004000	98473	1	804	1756	1765	49164	29500	18274			6.8	13	182	750	905				Lower Mannville
0645181004000	98473	2	804	1756	1765	56308	33980	20735			7.6	16	314	880	780				Lower Mannville
0645183004000	122031	0	779	1689	1698	32662	19000	12300			8.0	178	91	329	580				Lower Mannville
0645190306000	98490	1	758	1740	1744	70682	43000	25554			6.7	21	516	1351	488				Lower Mannville
0645192207000	98540	1	747	1651	1658	67475	40840	24088			7.2	15	466	1623	900				Lower Mannville
0645193410000	98559	2	747	1672	1686	62011	37500	22523			7.5	9	462	1092	865				Lower Mannville
0645201410000	98570	1	818	1786	1799	54815	32920	20100			7.3	18	190	1105	980				Lower Mannville
0645210702000	98579	1	791	1911	1935	56890	34100	21204			6.6	12	183	855	1090				Lower Mannville
0645213011000	98589	3	819	1829	1847	59056	35750	21627			6.5	62	170	1241	420				Lower Mannville
0645261612000	122322	0	888	2285	2302	38532	21500	15600			8.0	112	30	49	1170				Lower Mannville
0646082506000	98707	2	1046	3141	3149	85654	52100	30365			7.0	10	376	2542	531				Lower Mannville
0655160202000	163334	0	1034	1776	1885	66203	40600	23300			6.9	3	231	964	505				Lower Mannville
0655170810000	100920	1	815	1586	1594	61790	37289	22556			7.6	7	298	1187	709				Lower Mannville
0655172811000	100926	1	882	1667	1709	53085	31853	19679			7.3	4	144	932	961				Lower Mannville
0655180110000	100931	3	803	1606	1617	65627	39585	24110			7.8	84	393	1032	900				Lower Mannville
0655182411000	100938	1	822	1639	1658	60315	36300	22483			6.6	10	255	811	928				Lower Mannville
0655182911000	100940	2	859	1660	1680	56624	34000	21329			8.0	19	177	646	920				Lower Mannville
0655191104000	100953	2	794	1655	1660	66787	40334	24641			7.7	9	464	872	950				Lower Mannville
0655191104000	100953	3	794	1693	1706	67059	40334	24904			7.5	7	384	850	1180				Lower Mannville
0655192907000	100962	3	786	1625	1650	61969	37500	22381			7.0	23	608	1001	927				Lower Mannville
0655202510000	100979	6	743	1601	1613	55940	33600	21087			8.1	29	193	597	883				Lower Mannville
0655212802000	100991	2	765	1760	1771	65786	39480	24869			7.1	3	194	689	1120				Lower Mannville

DLS	ID	#	elev	dtop	dbot	TDS	Cl	Na	Na _c	K	pH	SO ₄	Mg	Ca	HCO ₃	Ca _{ox}	Na _{cl}	Na/Cl	Aquifer
0655212802000	100991	1	765	1704	1710	59361	35960	21030			6.4	18	866	941	1110				Lower Mannville
0655223411000	101004	1	722	1753	1777	53528	31900	20416			7.1	2	129	448	1288				Lower Mannville
0656022206000	101065	3	789	2155	2174	37939	22500	14443			7.8	20	93	344	1090				Lower Mannville
0665161216000	102285	1	881	1578	1606	65359	39396	23824			6.8	176	256	1376	673				Lower Mannville
0665162508000	102297	1	875	1490	1501	40637	24024	15265			6.8	45	131	516	1335				Lower Mannville
0665181004000	102312	2	814	1576	1585	58210	35060	21555			7.0	10	188	994	820				Lower Mannville
0665181810000	102314	3	810	1600	1616	78371	47500	28232			6.6	13	479	1734	840				Lower Mannville
0665181810000	102314	2	810	1568	1578	68477	41400	25083			6.7	18	260	1357	730				Lower Mannville
0665210910000	102346	3	741	1630	1648	56603	33750	20890			6.5	178	189	1018	1175				Lower Mannville
0665221110000	102366	1	734	1661	1665	50751	30600	18788			7.0	16	236	768	698				Lower Mannville
0665230910000	102384	2	779	1747	1760	46922	28400	16699			7.1	33	457	989	701				Lower Mannville
0665262303000	102417	2	760	2005	2010	55616	33150	21383			7.5	25	145	289	1270				Lower Mannville
0666052610000	102440	4	794	2210	2242	65923	39450	24887			6.5	33	182	741	1280				Lower Mannville
0675170810000	103463	1	831	1522	1527	61337	37010	22598			6.8	24	268	1050	787				Lower Mannville
0675210210000	103526	1	748	1579	1590	46413	27600	17507			6.9	18	145	524	1280				Lower Mannville
0675212815000	103533	1	707	1500	1506	48100	28770	18008			0.0	2	293	462	1150				Lower Mannville
0675221706000	103541	1	701	1625	1631	55016	32400	20955			7.6	8	122	524	2048				Lower Mannville
0675221706000	103541	2	701	1554	1570	43664	26200	16001			7.5	16	197	827	860				Lower Mannville
0675231511000	103565	7	749	1726	1729	52498	30783	20071			8.0	35	160	374	2185				Lower Mannville
0675231511000	103565	4	749	1622	1629	42994	25818	15783			7.5	34	431	456	960				Lower Mannville
0675232106000	103567	3	757	1661	1669	45304	26940	16888			7.3	7	154	681	1290				Lower Mannville
0675242110000	103573	2	751	1798	1818	51242	29990	19613			7.1	18	136	379	2250				Lower Mannville
0676050510000	103602	2	785	2220	2223	82047	49435	30579			6.8	50	210	1289	986				Lower Mannville
0676050810000	103604	7	778	2191	2198	63634	38391	23446			7.5	70	112	1312	617				Lower Mannville
0685040306000	161914	0	745	2105	2252	72867	44000	26105			6.8	58	209	857	1513				Lower Mannville
0685040306000	161917	0	745	2105	2252	69407	41500	25738			7.7	86	243	721	994				Lower Mannville
0685191916000	104422	1	759	1475	1480	41069	23814	15969			7.4	13	59	157	2151				Lower Mannville
0685192811000	104423	3	796	1454	1481	47259	28210	17502			7.0	3	167	801	1171				Lower Mannville
0685193410000	104424	2	814	1490	1503	47655	28550	17492			6.8	10	200	901	1020				Lower Mannville
0685202307000	104430	2	768	1498	1506	57333	33800	22120			6.8	13	172	220	2050				Lower Mannville
0685232511000	104531	3	725	1506	1518	36809	21800	13633			7.2	10	190	549	1274				Lower Mannville
0685232511000	104531	4	725	1579	1593	52414	30500	19796			6.7	18	156	620	2692				Lower Mannville
0685240410000	104533	1	759	1629	1642	41559	23540	15342			7.5	132	187	753	3265				Lower Mannville
068524110000	104536	1	743	1602	1611	38310	23000	14048			8.1	15	284	562	815				Lower Mannville
0685241606000	104537	1	736	1679	1689	52485	30750	20041			7.8	4	134	440	2270				Lower Mannville
0685251314000	104540	3	754	1748	1757	55103	32064	21317			8.0	17	138	222	2735				Lower Mannville
0685252606000	104542	3	708	1670	1684	57246	33620	22029			6.5	44	111	361	2200				Lower Mannville
0685262901000	104546	2	671	1711	1718	51190	30159	19579			8.0	13	171	331	1905				Lower Mannville

DLS	ID	#	elev	dtop	dbot	TDS	Cl	Na	Na _c	K	pH	SO ₄	Mg	Ca	HCO ₃	Ca _{ox}	Na _{cl}	Na/Cl	Aquifer
0685262901000	104546	3	671	1734	1740	53107	31156	20512			8.0	9	158	195	2190				Lower Mannville
0686022606000	104558	2	675	1858	1869	54169	32090	20985			7.0	5	127	170	1611				Lower Mannville
0686041310000	153263	1	738	2063	2073	51771	31041	19590			7.5	13	187	477	941				Lower Mannville
0686042110000	104576	2	669	1999	2023	57107	34200	21461			6.5	32	228	633	1125				Lower Mannville
0686042110000	104576	6	669	2012	2016	58385	34960	22360			7.0	21	112	431	1020				Lower Mannville
0686073511000	104629	5	674	2232	2238	83910	50761	30649			6.6	7	540	1437	1051				Lower Mannville
0686081106000	104634	7	811	2467	2484	89917	55000	31352			6.1	107	841	2499	240				Lower Mannville
0695210507000	105382	1	658	1358	1362	47116	27567	17780			7.1	10	207	470	2200				Lower Mannville
0695210704000	105405	1	642	1345	1350	44050	25250	16771			6.7	6	241	270	3075				Lower Mannville
0695211110000	105417	1	695	1377	1407	45989	26430	17800			6.9	4	131	177	2943				Lower Mannville
0695220201000	105434	2	657	1381	1399	42875	24963	16152			7.6	37	171	481	2178				Lower Mannville
0695221609000	105490	2	686	1463	1472	50303	29294	19238			7.5	22	155	365	2500				Lower Mannville
0695230606000	105514	2	728	1535	1546	35158	20950	12914			7.8	7	264	502	1060				Lower Mannville
0695230606000	105514	3	728	1639	1646	52796	31250	19279			7.3	5	396	873	2020				Lower Mannville
0695251306000	105527	1	758	1573	1594	38635	23125	14245			7.4	3	209	609	903				Lower Mannville
0695251907000	105528	4	772	1603	1608	36425	21846	13316			7.3	16	206	662	770				Lower Mannville
0696050107000	138058	0	662	1998	2002	47757	27000	19100			7.9	103	78	255	1120				Lower Mannville
0695220503000	124829	0	696	1588	1611	110066	66600	38985	41019	156	6.9	1646	471	1842	366	21	-173	0.950	Nordeg
0625213100000	82752	1	1050	3296	3391	122460	74000	45598			6.9	224	461	1722	925				Nordeg
0555181410000	87433	3	1023	2595	2622	67922	40500	24945			6.8	64	194	1402	1660				Nordeg
0565162404000	89377	3	939	2239	2243	50866	30225	18731			7.5	67	223	900	1465				Nordeg
0565213210000	89451	2	964	2783	2789	129286	78466	47979			7.4	198	638	1741	537				Nordeg
0585220606000	92045	2	1027	2857	2863	120140	72600	44669			6.4	27	228	2090	1070				Nordeg
0615222507000	95018	3	964	2393	2397	108053	65450	40128			6.9	284	401	1602	381				Nordeg
0645213611000	98595	1	778	1882	1893	156820	94800	57431			6.1	492	559	3103	885				Nordeg
0665152804002	123331	0	1026	1692	1702	26600	15000	9450			6.0	1210	103	606	22.3				Nordeg
0675220211000	103536	1	704	1730	1739	155078	93900	56750			7.3	604	646	2951	460				Nordeg
0685193410000	104424	3	814	1580	1596	127660	77300	46801			6.8	436	559	2323	490	-33	-234	0.963	Nordeg
0655252408000	123010	0	900	2204	2218	130619	78700	48600	49135	1120	6.9	293	247	1010	648	-16	-233	0.952	Triassic
0675201810020	141776	1	787	1712	1720	145492	87800	55072	54188	1500	6.4	601	284	1540	396	-6	-199	0.945	Triassic
0696040310000	105539	1	666	2074	2082	133578	80540	50237	49352	1500	6.9	380	363	1603	927	7	-203	0.942	Triassic
0645221610000	98597	4	811	2053	2056	141339	85186	52891	52036	1450	6.9	681	346	1953	573	4	-156	0.937	Triassic
0675193206000	123976	0	753	1610	1621	116654	69100	43500	42007	1230	5.9	647	348	1550	125	12	-164	0.934	Triassic
0675201204000	123992	0	799	1698	1708	122025	76000	41100	46042	1550	6.3	650	368	1860	497	16	-194	0.932	Triassic
0685253504000	161175	0	711	1744	1764	153387	91800	56200	55506	1440	6.8	610	552	2280	503	39	-65	0.932	Triassic
0525193205000	160933	0	957	3027	3040	53756	31096	18000	18790	920	8.2	55	24	1440	2221	30	-159	0.929	Triassic
0675210214000	153245	1	744	1716	1722	130534	78500	48147	47316	1410	7.1	832	428	2280	706	32	-184	0.929	Triassic
0675212506000	163649	4	736	1650	1657	151007	91200	55736	54940	1350	6.6	834	508	2580	302				Triassic

DLS	ID	#	elev	dtop	dbot	TDS	Cl	Na	Na _c	K	pH	SO ₄	Mg	Ca	HCO ₃	Ca _{ex}	Na _{cl}	Na/Cl	Aquifer
0675243610020	103579	2	775	1833	1851	156668	94700	57769	57023	1264	6.5	683	620	2623	556	30	-190	0.928	Triassic
0656021806000	136004	0	858	2537	2542	159190	95100	59980	57256	1838	6.9	1095	607	2603	732	29	-190	0.928	Triassic
0675210214000	153245	3	744	1716	1722	127314	76500	46737	45941	1350	7.3	960	382	2480	560	42	-148	0.926	Triassic
0655211516000	177770	15	749	1868	1876	127411	76916	47025	46141	1500	6.4	558	206	2512	394	44	-147	0.925	Triassic
0645183004000	122026	0	779	1795	1799	142308	87400	49300	52341	1710	6.4	705	481	2440	107	29	-163	0.923	Triassic
0545222907000	85284	1	1027	3160	3180	132490	80400	49377	48084	2195	7.1	23	292	2122	563	21	-147	0.922	Triassic
0685212610000	141832	2	723	1579	1585	151444	91000	55205	54398	1369	5.8	1374	705	2903	522	48	-165	0.922	Triassic
0685240307000	104532	3	749	1807	1832	149221	90250	54478	53758	1220	7.4	667	729	2803	598	44	-155	0.918	Triassic
0665213508000	102362	2	756	1758	1760	148811	90000	54279	53552	1232	7.4	656	741	2823	634	45	-152	0.918	Triassic
0635191608000	141089	1	786	1920	1925	129676	78500	47824	46705	1900	7.0	203	485	2250	842	29	-133	0.917	Triassic
06752210811000	124018	0	702	1688	1698	121181	74100	41515	43907	938	6.9	839	777	2402	610	41	-118	0.914	Triassic
0656200410000	89432	6	1208	3013	3037	120200	72500	44108	42952	1962	7.4	667	559	2082	577	27	-115	0.914	Triassic
0695201406000	105356	1	709	1474	1494	140540	85000	51177	50329	1438	6.5	658	826	2563	641	38	-133	0.913	Triassic
0695221813020	153317	1	722	1597	1607	148195	89500	53607	52914	1173	6.5	942	728	3203	439	65	-137	0.912	Triassic
0645192511000	163354	0	773	1894	1898	141487	86100	48900	50747	1860	7.0	706	471	3110	336	64	-125	0.909	Triassic
06752210106000	141777	1	770	1720	1762	154458	93600	55946	55103	1428	7.0	638	960	3023	593	51	-133	0.908	Triassic
0685252606000	124561	0	708	1755	1762	116547	67300	44100	39571	1170	6.5	388	517	2450	580	51	-93	0.907	Triassic
0685213514000	124419	0	715	1580	1585	163503	96000	59340	56405	1447	6.8	1769	1408	2963	576	46	-131	0.906	Triassic
0656021806000	136008	0	858	2537	2542	165677	102500	54388	59906	1955	6.8	963	1093	3604	866	71	-126	0.901	Triassic
0695221211000	105482	1	653	1504	1508	139928	84500	50303	49344	1627	7.2	790	778	3203	720	70	-102	0.900	Triassic
0655160802000	122723	0	908	1759	1767	114946	70100	38500	40775	1254	7.0	829	1063	2322	878	41	-78	0.897	Triassic
0655161113000	100916	2	1049	1860	1875	135402	81800	48502	47500	1700	7.0	704	510	3604	573	93	-88	0.895	Triassic
0645183004000	122028	0	779	1795	1799	147970	91700	47300	52893	3390	7.3	1190	903	3120	366	58	-83	0.889	Triassic
0695191509000	105328	2	785	1513	1551	113391	68900	39879	39106	1310	6.2	570	1361	2382	610	46	-34	0.875	Triassic
0535193402000	83939	2	985	2872	2881	92106	55334	34264			7.6	37	134	1659	1377				Triassic
0545221107000	85280	1	1071	3203	3307	134002	81500	49306			6.5	39	753	2082	654				Triassic
0565221807000	89454	1	1191	3207	3210	130030	79080	47959			6.7	12	594	2110	600				Triassic
0565222006000	89455	2	1178	3157	3162	131800	79800	48841			6.5	309	456	2106	586				Triassic
0565222006000	89455	3	1178	3161	3180	124778	75800	45609			6.1	128	563	2402	561				Triassic
0565222507000	89456	1	897	2822	2841	127129	76912	47116			7.2	154	298	2248	815				Triassic
0565231304000	89458	1	1131	3165	3196	140565	85200	52356			6.4	20	347	2234	830				Triassic
0575213210000	90853	1	965	2676	2691	126626	76360	47329			7.1	56	328	1857	1415				Triassic
0575213410000	90854	1	984	2670	2684	125844	76000	47119			6.6	152	156	1985	880				Triassic
0585202604000	92025	7	929	2489	2494	105751	63900	39205			7.6	188	316	1760	776				Triassic
0605163509000	93736	1	764	1812	1845	90134	54670	31330			7.7	16	438	3200	976				Triassic
0615182006000	94927	4	980	2215	2221	126661	76575	46188			6.5	446	414	2733	620				Triassic
0615203010000	94983	1	877	2228	2242	137484	83200	51419			6.1	100	340	1986	893				Triassic
0615203510000	94992	1	872	2199	2214	116526	70430	43464			7.4	113	339	1722	933				Triassic

DLS	ID	#	elev	dtop	dbot	TDS	Cl	Na	Na _c	K	pH	SO ₄	Mg	Ca	HCO ₃	Ca _{ex}	Na _{cl}	Na/Cl	Aquifer
0625150406000	95795	2	920	1900	1916	121065	73500	44819			6.5	218	414	1979	273				Triassic
0625161410000	95807	2	971	1974	1984	115330	69580	41827			7.3	308	437	2640	1093				Triassic
0625161410000	95807	3	971	1974	1984	114699	69225	42012			7.8	283	122	2680	766				Triassic
0625210212000	96015	1	880	2213	2256	122551	73997	45926			6.9	211	248	1754	845				Triassic
0625211412000	96027	1	796	2120	2135	144519	87600	53989			6.8	257	391	2066	440				Triassic
0625211610000	96028	1	839	2169	2195	115389	70031	42952			7.5	14	335	1784	556				Triassic
0635140707000	120993	0	928	1803	1809	87076	51118	31985			7.9	1069	251	1443	1210				Triassic
0645160410000	98452	2	921	1829	1844	128325	77257	47054			7.5	580	432	2460	681				Triassic
0655220107000	100995	2	786	1942	1957	148332	90000	54385			6.8	403	790	2503	510				Triassic
0655223411000	101004	2	722	1841	1856	147527	89158	54793			6.2	319	270	2591	805				Triassic
0655223411000	101004	3	722	1841	1856	146243	88453	54337			6.2	259	270	2550	761				Triassic
0655212302000	102357	2	724	1725	1750	154693	93500	56967			6.3	455	243	3204	660				Triassic
0675210210000	103526	2	748	1721	1727	145037	87340	52868			6.6	940	565	2980	701				Triassic
0675210210000	103526	3	748	1721	1727	147833	89400	53532			6.3	668	661	3267	620				Triassic
0675210606000	103527	1	661	1664	1677	145440	87985	53442			6.5	592	522	2683	438				Triassic
0675210811000	124012	0	702	1704	1714	144983	89500	46345			7.4	889	1578	5005	610				Triassic
0675212815000	103533	2	707	1721	1725	149778	90340	54214			0.0	1080	660	3298	378				Triassic
0675220211000	103536	2	704	1730	1739	151238	91370	55642			7.4	576	468	2790	370				Triassic
0675221610000	103540	2	694	1689	1702	143982	86900	53000			6.6	474	491	2635	980				Triassic
0675243506000	103577	3	767	1939	1960	149925	98859	54857			7.3	1455	515	3123	644				Triassic
0675243506000	103577	4	767	1939	1960	149197	89386	54406			7.2	1457	477	3144	664				Triassic
0675243506000	103577	5	767	1850	1857	148706	89623	54856			7.1	701	490	2613	859				Triassic
0675243610020	103579	4	775	1839	1844	152851	92450	56013			7.2	611	710	2739	666				Triassic
0685191916000	104422	2	759	1568	1573	129938	78658	47605			7.2	492	683	2229	551				Triassic
0685192811000	104423	6	796	1578	1597	136326	82344	50346			6.4	539	429	2376	595				Triassic
0685211903000	124406	0	656	1562	1564	152161	91818	54205			6.6	798	918	3691	519				Triassic
0685212607000	104444	1	720	1573	1585	148337	89500	53262			6.8	858	790	3504	859				Triassic
0685212607000	104444	2	720	1573	1585	148929	89890	53842			7.4	877	685	3270	302				Triassic
0685221014000	163677	12	669	1609	1614	156623	95000	56823			6.8	683	1093	2803	451				Triassic
0685221014000	163677	13	669	1610	1612	151659	92000	54302			6.5	702	1165	3223	542				Triassic
068522303020	104474	1	658	1565	1575	159757	96600	58651			6.5	644	588	2979	600				Triassic
068522303020	104474	2	658	1558	1567	152167	92000	55678			6.6	642	608	2939	610				Triassic
0685222407000	104481	1	648	1547	1549	151903	91818	54211			6.6	798	918	3691	519				Triassic
0685222407000	104481	2	648	1547	1549	151903	91818	54211			6.6	798	918	3691	519				Triassic
0685222409000	104482	1	645	1544	1551	150459	91410	54347			6.8	4	462	3763	520				Triassic
0685223207000	104499	2	701	1606	1623	148848	90000	54173			6.6	685	632	3083	560				Triassic
0685223307000	104501	6	688	1591	1597	151299	91853	54311			6.8	671	974	3350	285				Triassic
0685223307000	104501	8	688	1591	1597	155909	94335	56995			7.1	700	406	3350	250				Triassic

DLS	ID	#	elev	dtop	dbot	TDS	Cl	Na	Na _c	K	pH	SO ₄	Mg	Ca	HCO ₃	Ca _{ex}	Na _{ar}	Na/Cl	Aquifer
0685230510000	104524	1	789	1833	1855	149553	90385	54266			6.4	693	784	3043	776				Triassic
0685232511000	104531	5	725	1670	1688	152789	92400	55359			6.5	700	797	3187	704				Triassic
0686042408000	104579	1	733	2171	2177	113640	69000	40574			6.6	347	610	2910	405				Triassic
0695192804000	105337	1	744	1470	1473	132779	80500	48376			6.2	546	904	2226	460				Triassic
0695210509020	105388	2	663	1505	1508	153425	92700	55645			6.9	866	765	3179	550				Triassic
0695210509020	105388	3	663	1505	1508	154107	93023	55519			6.7	867	532	3836	393				Triassic
0695210701000	105401	2	651	1498	1501	151009	91315	54166			6.2	791	888	3448	387				Triassic
0695210701000	105401	1	651	1440	1498	151202	91362	54788			6.7	558	827	3067	784				Triassic
0695210811000	105413	1	642	1485	1498	132410	80000	47096			6.8	823	1047	3051	800				Triassic
0695220103000	105426	2	653	1521	1525	119619	72000	43183			6.8	883	486	2803	537				Triassic
0695220103000	105447	1	675	1560	1562	137078	83000	49509			6.2	668	938	2683	570				Triassic
0695221201020	105474	1	641	1487	1495	157060	94874	57094			6.7	728	629	3352	623				Triassic
0695221201020	105474	2	641	1487	1495	150051	90681	54357			6.3	746	662	3302	616				Triassic
0695221205000	105477	1	654	1504	1507	150890	91356	53995			7.4	713	840	3688	605				Triassic
0695221207000	105479	4	652	1497	1503	152936	93100	52977			6.8	719	1485	4430	439				Triassic
0696012207000	105538	1	651	1820	1859	149970	90897	55558			6.5	396	798	2011	630				Triassic
0585152810000	152086	4	966	2130	2145	93563	56200	35029	34491	912	7.3	190	264	1280	1220	4	-141	0.946	Permian
0585152810000	152086	2	966	2130	2145	85498	51200	31571	31085	824	7.8	244	294	1500	1400	20	-114	0.936	Permian
0585152810000	91956	4	1106	2254	2262	104626	63000	39119	38177	1598	7.4	431	322	1400	720	3	-137	0.934	Permian
0625153608000	162674	1	894	1799	1803	81080	48500	29965	29228	1251	7.4	518	364	1241	1000	10	-98	0.929	Permian
0675243610020	103579	3	775	1934	1944	154885	92600	56403	55711	1173	6.3	1630	644	3123	986	57	-183	0.928	Permian
0585152810000	152086	3	966	2130	2145	91969	55600	33969	33391	980	7.4	248	299	1600	515	21	-108	0.928	Permian
0635150216000	97074	1	922	1816	1834	101139	61300	37591	36758	1415	7.6	144	287	1610	421	15	-116	0.925	Permian
0585152110002	91953	1	962	2150	2153	94318	56900	34766	34017	1820	7.3	488	440	2220	522	24	-155	0.924	Permian
0675222106000	103544	1	699	1800	1811	156970	94100	56792	56088	1193	6.2	1568	595	3584	673	79	-164	0.919	Permian
0675233006000	103571	5	776	1940	1945	155607	93400	56438	55660	1319	7.3	1514	705	3263	583	64	-162	0.919	Permian
0625142014000	95787	1	896	1797	1801	119302	72000	43785	42595	2020	7.1	56	410	2350	1425	41	-111	0.912	Permian
0625142014000	95787	3	896	1797	1801	115913	70000	42489	41411	1830	7.1	101	400	2320	1228	41	-108	0.912	Permian
0625142014000	95787	2	896	1797	1801	117541	71000	43063	41861	2040	7.2	12	410	2380	1376	43	-104	0.909	Permian
0635151206000	162746	1	911	1792	1806	105386	63600	38513	37473	1766	7.0	193	665	1786	1279	22	-92	0.909	Permian
0615151006000	169979	4	833	1848	1855	96586	58200	34965	34073	1515	7.3	432	486	2082	856	42	-74	0.903	Permian
0655161113000	100916	2	1049	1860	1875	135402	81800	48502	47500	1700	7.0	704	510	3604	573	93	-88	0.895	Permian
0615151508000	182960	1	845	1845	1850	119265	72000	43828			6.7	280	563	2050	1108				Permian
0635143506000	97070	2	1027	1811	1834	90564	54385	33448			6.7	250	270	1633	1176				Permian
0635150410000	97075	1	990	1902	1912	90013	53980	33179			6.9	230	252	1714	1340				Permian
0635151510000	97080	2	946	1830	1839	105052	63400	38850			6.3	155	467	1634	1110				Permian
0635162410000	177632	1	1034	1952	1964	120582	72600	44915			6.2	327	289	1910	1100				Permian

DLS	ID	#	elev	dtop	dbot	TDS	Cl	Na	Na _c	K	pH	SO ₄	Mg	Ca	HCO ₃	Ca _{ex}	Na _{cl}	Na/Cl	Aquifer
0655203310000	100980	3	742	1815	1830	133222	80300	48909			6.4	885	495	2441	390				Permian
0655211406000	100983	2	780	1958	1976	134963	81600	49145			6.2	805	554	2771	180				Permian
0655211715000	100986	7	729	1933	1937	141226	85398	50097			7.2	869	560	4149	313				Permian
0655260410000	101047	1	915	2532	2544	150342	90170	54847			7.2	1508	462	3161	395				Permian
0655260410000	101047	2	915	2532	2544	152797	91590	55559			7.1	1545	486	3360	522				Permian
0655261712000	102416	4	799	2345	2354	154713	94075	56456			7.3	40	510	3340	595				Permian
0675210210000	103526	5	748	1812	1822	104229	62600	37274			6.7	950	535	2595	560				Permian
0675212410000	103530	3	742	1753	1770	151967	91620	54784			6.4	1020	695	3530	646				Permian
0675220815000	103537	3	704	1804	1809	148926	89580	53833			0.0	1360	588	3416	307				Permian
0675221214000	103539	1	664	1762	1772	128513	77000	46201			6.8	1430	575	3065	492				Permian
0675222710000	103551	4	676	1743	1746	139536	83920	50499			0.0	1260	624	3044	385				Permian
0675230809000	103559	2	776	1973	1984	148839	88377	51700			7.0	1298	340	4293	761				Permian
0675242110000	103573	3	751	2004	2012	147286	88347	52634			6.9	1379	650	3752	445				Permian
0685220503000	104466	1	700	1778	1782	151078	90860	54218			8.0	1442	487	3484	635				Permian
0685230801000	104525	3	792	1931	1938	149658	89730	54202			6.4	1414	332	2786	742				Permian
0685240312000	177859	1	737	1914	1925	128643	76805	46941			6.4	1625	333	3320	1031				Permian
0685250606000	104542	6	708	1907	1920	161429	96400	59244			6.9	1419	1098	3618	615				Permian
0686020611000	104556	4	707	2325	2331	145175	87384	51353			6.2	1159	593	3379	990				Permian
0686041706000	104574	8	687	2475	2497	165409	99400	60392			6.2	257	840	3227	605				Permian
0695210609000	105396	3	650	1583	1590	140461	85398	50442			7.7	401	548	3144	665				Permian
0695221112000	105472	4	658	1603	1610	145578	88176	52982			6.5	107	144	3648	500				Permian
0695221609000	105490	3	686	1608	1625	148891	90363	54384			7.5	1320	1159	3781	298				Permian
0695251306000	105527	3	758	1912	1943	138412	83585	48420			1200	8.0	273	257	481	2299	-24	-148	Mississippian
0575161007000	90776	3	1051	2370	2383	78252	44981	29130	28423		1660	7.8	173	187	442	2250	-17	-109	Mississippian
0575161007000	90776	4	1051	2377	2380	62782	36884	23989	23012		1800	6.7	862	280	1501	1128	2	-170	Mississippian
0615152310000	94867	2	881	1885	1894	115681	69091	43392	42332		2200	7.4	716	350	1231	1621	-10	-165	Mississippian
0615152310000	94867	1	881	1885	1894	112905	67292	42519	41223		782	7.6	24	369	766	942	-8	-103	Mississippian
0495162511000	75191	2	1071	2984	2987	72442	43694	27126	26665		1650	7.7	31	310	1400	937	4	-128	Mississippian
0605151110000	93702	1	818	1879	1880	102585	62000	38383	37411		1293	7.4	979	395	1880	556	24	-134	Mississippian
0645173510000	98463	4	846	1740	1755	109609	65700	40381	38619		1790	7.3	480	364	1702	662	10	-144	Mississippian
0595150701002	169791	1	1008	2200	2202	117007	70547	43589	42534		1640	7.5	502	394	1914	686	17	-150	Mississippian
0645173510000	98463	3	846	1775	1790	123025	74200	45677	44711		1690	7.2	185	251	1120	393	-1	-105	Mississippian
0635143310000	121020	0	1029	1846	1853	86367	53300	29400	32047		1560	6.3	620	424	2250	363	29	-146	Mississippian
0675180310020	153241	4	823	1700	1719	129436	78200	47764	46844		1540	6.9	624	424	2360	730	36	-143	Mississippian
0675180310020	153241	1	823	1700	1719	128096	77200	47129	46222		1550	7.8	274	326	1430	1050	16	-96	Mississippian
0635151309000	97078	3	923	1800	1805	87198	52400	32252	31339		1680	7.4	35	194	978	1750	11	-64	Mississippian
0465151411000	107995	0	1210	3336	3340	61137	35500	21000	21221		1520	7.0	245	277	1698	1198	26	-100	Mississippian
0635152707000	97085	2	997	1885	1893	91739	55100	33830	32934										Mississippian

DLS	ID	#	elev	dtop	dbot	TDS	Cl	Na	Na _c	K	pH	SO ₄	Mg	Ca	HCO ₃	Ca _{ex}	Na _{cl}	Na/Cl	Aquifer
0675180310020	153241	2	823	1700	1719	123579	74600	45353	44516	1420	7.2	564	424	2360	566	39	-132	0.920	Mississippian
0555182110000	87446	1	1041	2651	2667	81565	49100	30166	29165	1700	6.8	29	299	1377	1208	17	-81	0.916	Mississippian
0605201716000	118818	0	952	2440	2459	128264	73600	48700	43681	2180	7.6	443	524	2000	817	22	-120	0.915	Mississippian
0565182110000	89399	2	1190	2724	2736	79688	47800	29420	28262	1967	7.1	58	233	1481	1415	23	-73	0.912	Mississippian
0565180306000	115769	0	1095	2645	2685	63342	36750	22061	21711	1337	6.9	91	316	1201	1586	21	-55	0.911	Mississippian
0565212811000	89450	1	1043	2951	2960	12714	76400	47293	45108	3714	7.2	568	287	2074	1055	22	-114	0.910	Mississippian
0675150311000	103448	1	940	1615	1638	104132	62600	37737	36953	1330	7.2	667	530	2178	854	42	-93	0.910	Mississippian
0675180310020	153241	5	823	1700	1719	124063	75000	45277	44257	1730	6.4	604	484	2510	383	46	-111	0.910	Mississippian
0575163011000	160941	0	1078	2382	2386	75446	45200	26200	26621	1930	7.8	5	238	1190	683	11	-65	0.908	Mississippian
0595173407000	92839	6	937	2160	2166	114323	69057	42201	40641	2650	7.1	3	305	2153	1228	34	-97	0.907	Mississippian
0555171506000	163212	0	940	2479	2490	72795	42500	24380	24979	1740	6.7	30	189	1586	1603	34	-59	0.906	Mississippian
0665153012000	102268	1	884	1593	1609	137224	83100	49575	48662	1548	6.9	609	996	2803	695	42	-107	0.903	Mississippian
0615151006000	169979	4	833	1848	1855	96586	58200	34965	34073	1515	7.3	432	486	2082	856	42	-74	0.903	Mississippian
0555171704000	163162	0	993	2621	2637	76447	44500	24495	26049	1720	7.6	26	335	1369	1047	21	-57	0.903	Mississippian
0545191107000	85216	1	993	2787	2810	90415	54400	32957	31789	1984	6.5	51	510	1722	1576	28	-67	0.901	Mississippian
0555182606000	140019	3	1051	2621	2637	76447	45900	27744	26704	1766	6.6	74	437	1562	1486	29	-51	0.897	Mississippian
0666061406000	102444	6	847	3096	3115	146023	88700	53294	51248	3476	6.6	285	471	3129	332	62	-84	0.891	Mississippian
0505190906000	79046	5	1052	3389	3392	68255	41023	24326	22925	2380	7.5	23	432	1751	1424	44	-5	0.862	Mississippian
0505190906000	79046	3	1052	3389	3392	68150	41023	23938	22561	2340	7.6	35	478	2001	1372	56	11	0.848	Mississippian
0475160207000	67762	3	1257	3451	3463	66934	40212	23661			8.0	49	441	1869	1428				Mississippian
0475160207000	67762	1	1257	3451	3463	67414	40491	23754			8.1	40	466	1925	1501				Mississippian
0475160207000	75197	4	1142	3197	3219	50486	29559	18755			7.1	96	201	793	2201				Mississippian
0495171211000	75217	3	1077	3423	3438	55441	33126	20844			7.2	27	167	687	1200				Mississippian
0495191306000	75217	2	1077	3423	3438	56785	33831	21320			7.4	163	107	805	1137				Mississippian
0505160611000	79026	1	1079	3025	3038	58680	33700	22906			6.8	103	40	210	3500				Mississippian
0505160611000	79026	1	1079	3041	3071	59366	34200	23170			6.9	99	43	207	3350				Mississippian
0505160906000	79027	2	1061	2950	2973	57697	33200	22558			7.2	76	31	185	3350				Mississippian
0505160906000	79027	1	1061	2952	3010	57980	33200	22638			8.1	184	50	182	3510				Mississippian
0505190906000	79046	4	1052	3389	3392	68478	41203	24255			7.7	39	478	1828	1372				Mississippian
0515160111000	81215	2	1056	2853	2875	50049	28362	19539			7.9	16	91	132	3881				Mississippian
0515160111000	81220	1	1106	2908	2931	55467	31700	21690			6.8	91	40	171	3610				Mississippian
0515170810000	81230	1	990	2926	2936	61733	37363	22021			7.0	14	773	1020	1103				Mississippian
0515181810000	81249	1	974	3049	3074	52857	31524	19455			8.4	142	207	960	1157				Mississippian
0515181810000	81249	2	974	3049	3074	56075	33548	20648			8.2	30	207	1040	1225				Mississippian
0515181810000	81249	4	974	3049	3074	64129	38163	23676			7.3	2	243	1140	1840				Mississippian
0515181810000	81249	3	974	3049	3074	65160	39050	24016			7.4	21	316	1080	1376				Mississippian

DLS	ID	#	elev	dtop	dbot	TDS	Cl	Na	Na _c	K	pH	SO ₄	Mg	Ca	HCO ₃	Ca _{ex}	Na _{cl}	Na/Cl	Aquifer
0515182710000	81252	2	1001	2970	2989	52074	30530	19857			7.6	16	146	440	2206				Mississippian
0515182710000	81252	1	1001	2970	2989	52155	30530	19897			7.3	33	170	400	2289				Mississippian
0525200210000	82732	4	1040	3214	3257	65736	39300	24107			7.2	86	253	1289	1425				Mississippian
0525201309000	82736	2	1036	3159	3161	60811	36500	22077			7.1	25	313	1289	1235				Mississippian
0525210407000	82744	1	1100	3400	3424	108457	64906	42008			7.8	181	172	396	1615				Mississippian
0525212406000	82750	1	1035	3313	3358	103655	62480	38674			7.3	4	292	1560	1313				Mississippian
0525213310000	82752	3	1050	3394	3397	127028	76600	47406			6.7	196	291	1962	1161				Mississippian
0535163404000	83808	1	899	2452	2460	63708	37000	24528			6.6	140	136	384	3090				Mississippian
0535173106000	83845	5	966	2668	2694	67047	39600	25313			7.0	115	136	841	2120				Mississippian
0535182606000	83898	2	960	2729	2743	79473	47000	30397			7.0	49	179	619	2500				Mississippian
0535183011000	83906	1	978	2797	2806	80406	47900	30801			6.8	257	107	633	1440				Mississippian
0535200810000	83949	1	1036	3131	3192	77624	45795	28474			7.5	528	219	1600	2050				Mississippian
0535211710000	83965	2	1066	3365	3392	120226	72500	44810			7.1	163	267	1926	1140				Mississippian
0535221512000	83969	4	1068	3414	3459	109865	65943	40972			7.4	165	202	1813	1566				Mississippian
0535221512000	83969	3	1068	3414	3459	124835	75087	46787			7.1	154	265	1792	1527				Mississippian
0545191302000	85227	2	995	2740	2755	87245	52400	32281			7.3	51	316	1469	1480				Mississippian
0545192506000	85252	1	981	2795	2802	97527	58770	36011			6.9	443	187	1825	220				Mississippian
0545233602000	85296	1	1099	3359	3376	121849	73094	44716			7.4	413	303	2492	1318				Mississippian
0555170506000	87406	4	946	2525	2533	75537	44700	28121			6.5	693	261	1074	1399				Mississippian
0555171606000	87409	1	953	2462	2485	75649	45826	27990			7.1	18	357	1139	649				Mississippian
0555183310000	87451	2	1094	2686	2695	77232	46300	28508			7.7	33	347	1277	1559				Mississippian
0565171310000	89388	2	984	2414	2429	70436	42000	26472			7.0	37	213	885	1686				Mississippian
0565191310000	89412	3	1194	2807	2815	95823	58000	35944			7.2	163	141	1405	347				Mississippian
0565193201000	89428	6	1330	2971	2977	127571	77454	46910			7.7	191	560	2213	495				Mississippian
0565212213000	89448	1	1115	3037	3057	92790	55500	34640			7.0	514	250	1343	1103				Mississippian
0565222006000	89455	7	1178	3240	3264	119290	71400	44373			7.1	464	295	1890	1387				Mississippian
0565222006000	89455	4	1178	3240	3264	124321	75000	46011			6.4	206	306	2243	1130				Mississippian
0575162710000	90782	5	1175	2472	2499	73483	43698	27732			6.7	39	160	911	1918				Mississippian
0575162710000	90782	1	1175	2474	2475	82914	49691	30976			7.8	26	270	1174	1581				Mississippian
0575162910000	90784	1	1076	2390	2401	83683	49878	30781			7.8	40	535	1280	2377				Mississippian
0575182510000	90804	1	1205	2637	2652	87341	52000	33482			7.4	142	236	521	1953				Mississippian
0575182806000	90806	1	1289	2751	2761	71449	59006	26290			7.2	191	247	1342	1260				Mississippian
0585152510000	91955	2	1047	2182	2192	98374	59006	36157			7.0	575	534	1560	1102				Mississippian
0585153307000	91960	1	955	2135	2136	108279	65375	39844			7.0	252	440	1818	915				Mississippian
0585192811000	92016	1	966	2457	2470	116284	70219	43074			7.7	369	372	1913	685				Mississippian
0585203311000	92033	1	978	2557	2571	93769	56600	34820			7.0	125	260	1546	850				Mississippian
0595150410000	92784	1	1021	2167	2180	103603	62210	38129			7.3	326	289	1965	995				Mississippian
0595150906000	92788	1	1008	2150	2157	108343	65588	38458			7.6	15	411	3278	1206				Mississippian

DLS	ID	#	elev	dtop	dbot	TDS	Cl	Na	Na _c	K	pH	SO ₄	Mg	Ca	HCO ₃	Ca _{ex}	Na _{cl}	Na/Cl	Aquifer
059515202000	92791	1	985	2073	2094	98231	59413	35931			7.3	163	447	1869	830				Mississippian
0595163104000	92824	2	975	2179	2184	115182	70000	41745			7.4	51	680	2332	760				Mississippian
0595163310000	92825	1	924	2073	2097	105536	63700	38047			6.5	168	428	2603	1200				Mississippian
0595180111000	92844	1	1041	2399	2405	140918	85500	50699			6.2	126	741	3323	1075				Mississippian
0595190810000	92880	3	911	2414	2429	134141	81000	49581			7.4	446	420	2316	769				Mississippian
0595192906000	92893	4	991	2455	2477	116622	70497	43037			7.4	369	420	1999	610				Mississippian
0595192906000	92893	3	991	2455	2477	129772	78554	47996			7.5	395	368	2260	405				Mississippian
0595192906000	92893	1	991	2455	2477	133098	80568	49162			7.4	301	473	2260	680				Mississippian
0595192906000	92893	2	991	2455	2477	134804	81575	49730			7.3	367	473	2347	635				Mississippian
0595202607000	92903	2	1009	2518	2536	125731	76100	46856			7.3	45	352	1920	932				Mississippian
0595202911000	92906	1	978	2506	2551	89682	54174	32592			6.7	68	262	2121	945				Mississippian
0595211611000	92913	2	1088	2660	2665	95030	57700	34255			6.9	78	656	1962	770				Mississippian
0595211611000	92913	1	1088	2660	2665	97564	59288	35256			7.2	8	572	2082	727				Mississippian
0595213604000	92919	2	1034	2595	2601	115067	69509	42487			8.0	119	227	2250	965				Mississippian
0595243404000	92941	3	1132	3024	3049	92891	55780	34332			7.8	461	272	1629	850				Mississippian
0605150410000	93693	1	854	1930	1944	108513	65300	40215			6.4	239	384	1746	1280				Mississippian
0605152012000	93709	2	807	1872	1879	90143	54400	32404			6.4	194	467	2162	1050				Mississippian
0605220906000	93853	2	1086	2739	2761	128358	77300	48015			7.2	8	318	1881	1700				Mississippian
0615150411000	94851	4	807	1829	1832	59485	35808	20035			6.4	15	411	1850	1620				Mississippian
0615151404000	94861	2	831	1830	1838	106436	64245	39737			7.5	246	731	2072	1206				Mississippian
0615161706000	94892	4	886	1994	2006	125604	76200	44810			7.4	400	363	1425	540				Mississippian
0615190410000	94943	1	955	2298	2318	123010	74300	44440			6.8	383	589	3371	509				Mississippian
0625142008000	95784	2	897	1800	1814	100704	60705	37266			7.1	588	593	2755	680				Mississippian
0625142008000	95784	2	897	1800	1814	100704	60705	37266			7.7	208	462	1520	1105				Mississippian
0625161410000	95807	4	971	2041	2053	123065	74195	45057			7.7	208	462	1520	1105				Mississippian
0625163006000	95814	3	954	2006	2017	130918	79400	48007			7.3	771	583	2200	527				Mississippian
0625181211000	95836	2	888	2030	2047	113037	68205	41405			7.4	165	316	2763	542				Mississippian
0625190614000	95858	2	869	2149	2190	139226	84000	51273			7.2	352	167	2565	698				Mississippian
0625191604000	95870	2	874	2149	2156	104778	63339	38279			6.7	617	467	2515	720				Mississippian
0625202711000	95994	1	838	2131	2164	120514	72511	44901			8.2	579	405	2078	200				Mississippian
0635171407000	97097	1	1039	2053	2070	104765	63000	38579			7.2	658	355	1760	670				Mississippian
0635220410000	97215	3	840	2316	2347	97806	58700	35867			6.9	609	389	1834	720				Mississippian
0645153203000	98449	2	990	1809	1851	94546	56900	34837			6.5	741	292	1930	561				Mississippian
0645192207000	98540	2	747	1846	1858	150006	90869	53284			6.9	323	340	1682	943				Mississippian
0645201410000	98570	2	818	1986	1996	150875	91000	55284			6.8	826	1140	3587	610				Mississippian
0645203606000	98576	3	768	1887	1900	134223	81000	49243			6.3	851	617	2803	650				Mississippian
0655160902000	100915	1	962	1807	1820	140072	84800	51439			6.9	693	452	2579	520				Mississippian
											7.4	574	680	2362	442				Mississippian

DLS	ID	#	elev	dtop	dbot	TDS	Cl	Na	Na _c	K	pH	SO ₄	Mg	Ca	HCO ₃	Ca _{ex}	Na _{cl}	NaCl	Aquifer
0655192907000	100962	6	786	1829	1850	154786	93600	56441			6.8	741	729	3003	555				Mississippian
0655202510000	100979	8	743	1808	1824	148388	89800	53681			6.8	770	826	3083	464				Mississippian
0655211101000	100982	3	769	1958	1966	148017	89300	53942			6.6	1040	519	3090	107				Mississippian
0665151815000	102251	1	990	1724	1733	131690	79483	48140			6.9	517	657	2418	966				Mississippian
0665161409000	102291	3	859	1608	1628	132426	80478	48316			7.2	10	388	2939	600				Mississippian
0665161409000	102291	1	859	1608	1628	138592	84000	50558			7.9	538	705	2603	384				Mississippian
0665162508000	102297	2	875	1597	1612	123754	74880	45485			6.1	422	530	2165	554				Mississippian
0665190815000	102323	4	773	1775	1782	134293	80900	49443			6.4	819	489	2358	576				Mississippian
0675153010000	103462	1	956	1618	1631	154933	93740	57740			6.6	465	430	2310	504				Mississippian
0685213613000	104462	1	704	1666	1670	113665	68200	41883			6.5	838	510	1826	830				Mississippian
0695221109000	105469	1	655	1658	1682	83060	50419	29899	64873	4680	6.6	61	476	1890	640	744	617	0.704	Wabamun
0695192602000	105335	1	822.6	2250	2270	220572	136100	60468	57964	4251	6	570	2357	20780	604	892	771	0.657	Wabamun
0635262812000	97303	1	897.6	3357	3360	246848	153000	66029	63641	4055	6.6	317	3183	24020	608	1036	933	0.641	Wabamun
0675243116000	103576	3	755.3	2751	2777	215334	134100	55645	53437	3750	6.4	737	4641	20060	307	859	919	0.614	Wabamun
0445162006000	61039	3	1191	4155	4164	116467	69500	37442			7.5	1350	593	6775	1641				Wabamun
0495182210000	75209	1	1041	3725	3766	120792	71583	39921			7.6	1300	619	6062	2658				Wabamun
0525211610000	82748	4	1095	3850	3901	169938	104000	55874			6.9	158	1162	8440	618				Wabamun
0575170915000	90788	4	1156	3001	3016	198833	123825	49877			7.7	197	3024	21736	355				Wabamun
0575191411000	90816	1	1136	3014	3077	176438	108800	49239			5.2	769	2029	15576	49				Wabamun
0575193411000	90832	4	1201	3182	3185	194739	119800	56889			6.2	33	1555	15936	1070				Wabamun
0585251010000	92062	1	1124	3735	3762	159736	97900	43024			6.8	173	1226	16500	1855				Wabamun
0625140710000	95782	2	1063	2324	2331	189796	117480	51344			7.2	477	2976	17178	695				Wabamun
0645252111000	98642	1	837	3057	3082	212603	131200	58473			7.4	517	2391	19692	670				Wabamun
0646041506000	98680	2	887.3	3822	3830	194456	120520	47661			5.65	380	1710	24000	138				Wabamun
0655180110000	100931	4	802.8	2316	2339	196539	121590	51386			7.1	366	2650	20056	1000				Wabamun
0675192414000	103513	1	767.5	2265	2304	211759	131750	54992			6.5	448	3718	20701	305				Wabamun
0676053107000	103618	3	684.6	3498	3611	226303	139800	62865			6.2	617	3256	19379	785				Wabamun
0686040406000	104568	5	727.3	3374	3423	212093	130600	56226			6.3	698	2211	21822	1090				Wabamun
0686041706000	104574	9	686.7	3369	3380	253153	156600	71103			5.7	216	2746	22262	460				Wabamun
0686042110000	104576	4	669.3	3303	3335	227830	140800	63041			5.9	574	2819	20380	440				Wabamun
0695210510000	105389	1	660.2	2284	2288	261291	162400	69804			6.3	318	4131	24424	435				Wabamun
0695210703000	105402	3	650.7	2333	2345	232641	144500	61030			7.4	279	3770	22659	820				Wabamun
0695216090000	105490	5	685.8	2391	2405	228075	142992	54382			6.5	316	5520	24624	490				Wabamun
0696050805000	105548	2	660.2	3231	3307	237796	148200	59326			5.8	178	3985	25785	655				Wabamun
0696051610000	105551	5	659.6	3294	3316	265297	164400	72829			5.3	146	2381	24024	720				Wabamun
0525150706000	139132	1	920	3068	3073	144324	86500	52339	50954	2350	7.0	762	457	3411	1739	78	-124	0.908	Winterburn
0525161306000	82662	2	946	3084	3105	158086	95000	57575	55873	2890	7.1	690	437	3604	1586	79	-133	0.907	Winterburn

DLS	ID	#	elev	dtop	dbot	TDS	Cl	Na _{cl}	K	pH	SO ₄	Mg	Ca	HCO ₃	Ca _{eq}	Na _{eq}	Na/Cl	Aquifer
0465170306000	64906	3	1307	4381	4384	130674	78460	47746	2813	8.0	914	304	2869	776	60	-107	0.906	Winterburn
0465170306000	64906	6	1307	4380	4383	144657	87300	52824	3853	7.1	636	323	3437	886	79	-79	0.889	Winterburn
0665151602000	123314	0	1007	2395	2408	149867	90900	49060	1672	7.7	1827	1348	3984	176	102	-54	0.878	Winterburn
0435150406000	58848	4	1400	4618	4627	137054	83465	48651	3700	7.0	19	197	4379	292	130	-11	0.862	Winterburn
0665151616000	123316	0	968	2250	2421	157787	93800	53500	1920	7.4	970	914	5920	763	196	10	0.854	Winterburn
0665150513000	153203	1	936	2352	2368	186212	114000	58028	3225	7.6	646	1700	10610	464	408	272	0.773	Winterburn
0695261810000	124954	0	664	2846	2853	191507	117500	50600	3960	6.1	340	2890	16100	170	679	658	0.659	Winterburn
0675243116000	103576	2	755	2798	2815	214594	133300	55047	3782	6.8	724	3912	21380	471	925	927	0.611	Winterburn
0515213311000	81274	2	1128	4019	4075	131567	79500	43025		7.3	881	633	7068	935				Winterburn
0545191302000	85227	8	995	3445	3462	202090	124000	58846		6.5	583	2503	15415	1510				Winterburn
0545191802000	85246	3	1041	3453	3493	192444	118400	54415		6.7	432	2211	16416	1160				Winterburn
0545220607000	85279	6	1017	3919	3928	160575	98818	51564		7.6	117	751	9688	3333				Winterburn
0555191914020	87459	3	1147	3516	3625	152753	91850	49875		7.7	506	849	8226	2943				Winterburn
0565211806000	89447	1	1020	3606	3627	119031	72220	39006		7.9	342	1703	4801	1950				Winterburn
0575230607000	90862	1	1060	3776	3787	147290	89425	49086		6.8	396	719	7113	1122				Winterburn
0585171506000	91970	2	1177	3063	3079	205805	125696	57560		6.6	1249	2025	18550	1475				Winterburn
0585172908000	91976	1	1066	2910	2918	183345	112960	52372		7.1	58	1593	15907	926				Winterburn
0585201807000	92022	1	872	3080	3088	170473	105600	41223		6.6	584	4301	17660	2288				Winterburn
0595162210000	92821	2	923	2665	2673	201775	124539	58642		7.0	14	2059	16147	762				Winterburn
0595163104000	92824	5	975	2735	2758	198614	122400	58192		7.0	385	2503	14755	770				Winterburn
0635240601000	97236	5	878	3239	3246	208606	127270	55482		7.4	457	1382	21750	620				Winterburn
0636010110000	97310	4	1012	3651	3689	211593	130500	57325		6.7	517	1980	20962	630				Winterburn
0636021312000	97326	2	991	3780	3853	223783	138200	62051		6.1	410	2673	20060	790				Winterburn
0645240514000	98627	1	853	3111	3138	172468	106932	46805		6.9	148	2184	16226	350				Winterburn
0655192302000	100959	2	839	2493	2500	190731	117730	52387		7.1	481	3144	16340	1320				Winterburn
0655211406000	100983	4	780	2613	2623	215597	133000	59408		6.5	420	2673	19540	1130				Winterburn
0665161306000	102286	1	881	2309	2329	178942	109421	56769		6.5	550	1417	10473	634				Winterburn
0665161314000	102288	2	902	2332	2377	174251	106336	56502		6.1	539	1126	9437	634				Winterburn
0665161402000	102290	3	857	2289	2300	182317	118000	59988		7.5	671	2066	11411	370				Winterburn
0665230411000	102381	8	755	2769	2783	172653	106044	46810		6.6	680	1997	16718	1269				Winterburn
0665250211000	102401	3	793	3002	3048	219715	135600	61045		5.9	487	2474	19785	660				Winterburn
0675150107000	103442	2	1004	2327	2338	190668	117676	55675		6.4	408	2163	14655	180				Winterburn
0675162607000	103460	5	943	2248	2254	210537	130700	53728		0.0	470	3430	21840	750				Winterburn
0675212815000	103533	5	707	2467	2473	205837	127280	55244		0.0	390	2610	19920	800				Winterburn
0676043210000	103599	9	693	3374	3520	219423	134600	61238		6.5	1035	2304	19705	1100				Winterburn
0685170910000	104409	2	907	2330	2338	193477	119280	54930		6.1	384	2360	16100	860				Winterburn
0685181210000	104414	1	917	2365	2377	162864	100000	47527		7.5	728	1843	12535	510				Winterburn
0685230801000	104525	5	792	2777	2797	150257	92846	38420		6.4	633	2030	16080	505				Winterburn

DLS	ID	#	elev	dtop	dbot	TDS	Cl	Na	Na _c	K	pH	SO ₄	Mg	Ca	HCO ₃	Ca _{ex}	Na _{cl}	Na/Cl	Aquifer
0686040310000	104565	14	729	3485	3487	225140	139744	59476			6.0	254	3013	23360	595				Winterburn
0685210505000	105381	1	653	2342	2353	236423	146850	60530			7.3	344	3388	25011	610				Winterburn
0685232413000	105517	4	746	2539	2558	206413	128500	52151			6.6	329	3517	21680	480				Winterburn
0686050107000	105546	1	662	3356	3389	264089	163800	71878			5.9	321	3492	24431	340				Winterburn
0686051107000	105549	3	667	3435	3456	254434	157700	69700			6.8	272	3159	23420	372				Winterburn
0686052110000	105552	1	661	3301	3334	254173	157200	69676			5.6	206	2406	24424	530				Winterburn
0686051107000	105549	7	667	3484	3489	253687	157100	69470	67184	3880	6.4	432	2897	23710	159	1016	878	0.659	Woodbend
0635260109000	141102	5	874	3527	3542	242983	150000	66485	64017	4190	6.6	286	2420	23300	1000	1003	844	0.658	Woodbend
0675233006000	103571	2	776	2797	2810	242322	149700	65189	62967	3771	6.4	776	2965	23420	554	1010	882	0.649	Woodbend
0675222106000	103544	2	699	2705	2726	241137	150000	64107	62154	3314	6.2	436	4374	22020	407	940	925	0.639	Woodbend
0595243507000	92942	1	1082	3839	3849	229921	142500	61563	58771	4742	6.2	329	2469	23000	122	996	890	0.636	Woodbend
0685220111000	105431	1	654	2557	2565	206888	129090	50087	49591	3550	6.5	232	3360	23972	300	888	794	0.627	Woodbend
0685221414002	177858	1	659	2576	2594	215601	134000	56047	53992	3660	6.6	258	3110	22000	377	955	897	0.620	Woodbend
0675231208000	103562	1	725	2685	2707	246826	153500	62412	60062	3989	6.5	430	3523	26830	286	1176	1100	0.603	Woodbend
0625263305000	120516	0	947	3784	3804	240862	147700	56210	53998	4389	5.6	317	4735	26750	761	1178	1224	0.564	Woodbend
0515203006000	81270	2	1085	4047	4203	157833	96396	45883			6.6	910	1734	12376	1087				Woodbend
0515253011000	81285	15	1344	5357	5615	135741	84000	34885			6.0	301	3003	12773	1585				Woodbend
0525202306000	82739	4	1017	3788	3824	210729	130100	58943			7.0	364	1944	19220	323				Woodbend
0525211616000	82748	5	1095	4105	4119	175752	108600	49622			6.9	240	1770	15400	244				Woodbend
0525221030000	82755	1	1195	4321	4339	159255	94800	56616			7.0	339	802	4528	4820				Woodbend
0525232604000	161891	2	1151	4464	4473	183110	113900	51680			6.9	319	4419	12430	737				Woodbend
0525236140000	82771	17	1280	5200	5260	144018	90000	36956			6.7	150	3600	13000	634				Woodbend
0535191709000	83930	2	985	3697	3751	212693	129800	60425			7.4	1363	2527	17698	1810				Woodbend
0545191302000	85227	5	995	3481	3492	174546	104800	50663			7.9	1473	1487	14398	3510				Woodbend
0545201100000	85256	28	1085	3712	3716	182028	113597	42106			6.3	314	3829	21673	1035				Woodbend
0545202307000	169475	1	1139	3724	1000	198591	124000	49398			6.3	330	4500	20000	737				Woodbend
0545233602000	85296	2	1089	4051	4053	157132	95420	52734			6.8	37	661	7452	1684				Woodbend
0545233602000	85296	9	1089	4141	4143	168676	102479	55392			7.4	82	747	9061	1861				Woodbend
0555170506000	87406	5	946	3338	3399	184456	112400	53785			7.1	1286	1652	14815	1052				Woodbend
0555181507000	87434	4	970	3273	3283	215556	132600	62132			6.2	265	1895	18138	1070				Woodbend
0555181702000	87437	1	989	3320	3360	151175	91631	42015			6.9	1057	786	14867	1664				Woodbend
0555181710000	87439	1	988	3314	3334	197695	121400	55719			6.4	734	2260	17017	1150				Woodbend
0555192010000	87462	3	1127	3676	3744	207561	128400	55046			6.8	200	2430	21002	981				Woodbend
0555192211000	140022	1	1077	3482	3488	175026	107000	49457			6.5	730	1400	15900	1300				Woodbend
0555192312000	87463	2	1081	3516	3523	198275	122581	51509			6.7	187	2006	21497	1005				Woodbend
0555201111000	87478	5	1158	3944	3984	219987	135800	56043			7.0	128	1701	25626	1401				Woodbend
0555202607000	87481	3	1194	3752	3780	177707	108657	47354			6.6	506	1346	18822	2079				Woodbend
0555203109000	87486	3	1379	4068	4085	180284	110600	48582			7.7	595	1390	18530	1214				Woodbend

DLS	ID	#	elev	dtop	dbot	TDS	Cl	Na	Na _c	K	pH	SO ₄	Mg	Ca	HCO ₃	Ca _{ex}	Na _{cl}	NaCl	Aquifer
0555222305000	87500	7	1031	3841	3844	137624	82000	44866			6.7	267	770	7543	4430				Woodbend
0555222605002	151888	3	979	3760	3779	151249	92200	49274			7.1	8	1321	7576	1769				Woodbend
0555222608020	87503	10	929	3865	3887	133695	81200	40419					1604	8953	2380				Woodbend
0565161801000	89373	7	931	2930	2963	211681	130000	62315			6.9	290	1660	16900	1050				Woodbend
0565171310000	89388	4	984	3064	3079	199122	122400	60484			6.6	420	1702	13950	337				Woodbend
0565172813000	177196	2	1120	3196	3205	172975	106200	47641			7.8	837	2428	15260	1237				Woodbend
0565173615000	89393	1	1054	3078	3080	228383	141000	63463			6.2	302	2200	21100	647				Woodbend
0565200410000	89432	5	1208	3804	3850	144978	88300	36743			7.1	1251	1944	15820	1871				Woodbend
0565202307000	89439	4	1358	3886	3980	148181	90750	40400			6.0	642	1179	14730	978				Woodbend
0575170509000	90786	2	1127	3170	3226	174988	107500	48484			7.3	831	2408	15240	1072				Woodbend
0575171202000	140389	2	1096	3078	3087	201878	124000	57350			6.4	428	1520	18100	976				Woodbend
0575172310000	90782	5	1122	3130	3138	186930	115222	51850			6.7	44	1714	17519	1181				Woodbend
0575191010000	90810	4	1178	3430	3450	191052	118016	51583			7.2	48	2385	18312	1440				Woodbend
0575191411000	90816	2	1136	3375	3398	192217	118400	55618			6.3	40	1983	15576	1200				Woodbend
0575192310000	90822	6	1138	3397	3418	193734	119000	54543			7.3	120	1590	17600	1100				Woodbend
0575192310000	90822	2	1138	3397	3418	193734	119000	54543			6.4	28	2333	15936	1240				Woodbend
0575193506000	90835	5	1130	3315	3365	155794	95600	45210			6.4	267	1701	12372	1310				Woodbend
0585161706000	91964	1	1040	2920	2938	236333	145783	72731			6.6	407	1406	17322	1391				Woodbend
0585172506000	91975	1	1160	3155	3174	196744	121017	56625			6.6	572	1920	16320	591				Woodbend
0585190510000	92002	1	1053	3352	3353	170752	105000	49352			6.3	72	1983	13598	1520				Woodbend
0585181002000	92004	4	1227	3456	3486	175407	108000	52148			6.4	63	1871	12853	960				Woodbend
0585191016000	92008	1	1117	3375	3390	194692	119600	56986			6.5	222	1920	15295	1340				Woodbend
0585192215000	92014	4	1040	3348	3380	180519	110800	51181			7.3	447	816	17000	335				Woodbend
0585192811000	92016	2	966	3315	3324	207719	127581	56911			7.2	242	1314	20838	1490				Woodbend
0585200210000	92019	1	921	3383	3412	187507	115245	52241			6.8	370	1587	17515	1115				Woodbend
0585201511000	92020	5	922	3271	3279	211091	129400	56225			6.9	869	1871	21942	1594				Woodbend
0585202806000	92029	4	963	3319	3329	219323	135272	57068			6.6	216	1962	24071	1493				Woodbend
0585243416000	177306	1	1044	3840	3848	200067	122500	58563			6.9	527	1457	16420	1220				Woodbend
0585243416000	177306	4	1044	3773	3818	230617	143000	58811			7.0	422	3156	24820	830				Woodbend
0595152910000	92806	1	935	2706	2707	200906	123418	57754			6.5	283	1736	17007	727				Woodbend
0595153514000	92813	1	850	2570	2575	203398	125900	57242			6.8	317	2849	17140	305				Woodbend
0595163104000	92824	4	975	2853	2868	201926	124400	58273			6.5	349	2527	15856	1060				Woodbend
0595163310000	92825	3	924	2742	2786	198516	122200	57101			6.5	507	2576	15616	1050				Woodbend
0595173407000	92839	5	937	2863	2892	204487	125000	62298			7.4	741	1906	13960	1244				Woodbend
0595200707000	92899	3	1116	3441	3453	200056	123376	47440			7.2	226	1051	27239	1474				Woodbend
0595201710000	92901	5	1099	3523	3526	238285	148610	58109			6.6	391	5502	24940	1490				Woodbend
0595221503000	92927	8	1141	3781	3795	249344	154420	66126			7.1	295	3089	24977	890				Woodbend
0595222902000	92930	2	1145	3781	3799	251829	155400	70441			7.0	179	1823	23704	574				Woodbend

DLS	ID	#	elev	dtop	dbot	TDS	Cl	Na	Na _c	K	pH	SO ₄	Mg	Ca	HCO ₃	Ca _{ex}	Na _{af}	Na/Cl	Aquifer
0595241907000	92940	3	1190	3978	3988	213493	132000	59788			6.3	370	3360	17480	1046				Aquifer
0595263111000	92952	1	1187	4101	4108	211338	130000	53651			5.3	1222	2697	23180	1196				Woodbend
0605140616000	93674	2	799	2691	2704	197144	121073	57294			6.8	461	1803	16038	966				Woodbend
0605150103002	93686	1	824	2568	2621	205022	125565	61157			7.0	294	866	16677	942				Woodbend
0605150404000	93692	1	873	2637	2641	177440	108642	50477			6.7	689	1492	15603	1093				Woodbend
0605150404000	93692	2	873	2618	2635	194795	119750	55794			6.7	308	1595	16875	961				Woodbend
0605150710000	93698	2	853	2609	2615	189866	117000	53720			6.1	212	1830	16873	876				Woodbend
0605151906000	93708	2	823	2571	2591	162768	100000	47063			6.5	162	1104	14028	835				Woodbend
0605151906000	93708	5	823	2594	2597	204891	125692	62481			7.0	346	1799	14091	980				Woodbend
0605152012000	93709	4	807	2656	2672	185457	113600	54163			6.1	805	2012	14366	1040				Woodbend
0605153203000	93716	1	766	2594	2646	188359	116201	48519			6.9	616	2280	22080	1347				Woodbend
0605153306000	93717	2	757	2609	2640	186851	114817	53468			6.9	517	1835	15780	883				Woodbend
0605162012000	93726	2	816	2657	2665	222966	136965	63625			7.4	381	1798	19575	1263				Woodbend
0605162515000	93729	3	814	2580	2583	188996	116000	53940			7.0	319	1720	16200	695				Woodbend
0605171414000	93742	3	846	2657	2665	190255	117000	52632			7.2	389	1610	18000	365				Woodbend
0605171414000	93742	2	846	2657	2665	204180	126000	58104			6.5	351	2177	17302	500				Woodbend
0605173604000	93753	4	840	2865	2884	232936	143000	68443			8.3	356	1750	18820	1153				Woodbend
0605210311000	93836	1	1015	3384	3398	192715	121000	41704			7.0	195	5270	23800	839				Woodbend
0605210311000	93836	6	1015	3347	3355	196006	120500	51845			6.8	265	1700	20820	1781				Woodbend
0605210060000	93839	1	1008	3457	3487	217414	133684	59451			6.6	245	1239	22204	1202				Woodbend
0605263210000	93872	2	1245	4075	4092	250075	155000	66985			6.5	219	2772	24892	420				Woodbend
0615150602000	94852	5	762	2518	2520	202578	123879	61329			6.8	364	614	15983	834				Woodbend
0615150906000	94858	2	829	2705	2726	194350	119358	55118			7.1	533	1503	17439	811				Woodbend
0615151715000	94864	6	862	2736	2747	188168	115400	54602			7.1	545	1560	15500	315				Woodbend
0615151715000	94864	1	862	2745	2745	202953	125731	58620			6.9	218	3314	16638	879				Woodbend
0615160301002	94882	2	816	2599	2602	198844	121783	58890			7.0	1075	1546	17313	483				Woodbend
0615161307000	94889	7	832	2709	2728	182809	112700	52377			6.6	407	1774	15400	307				Woodbend
0615220805000	95013	1	1035	3408	3411	210724	130532	54721			6.5	123	1984	23069	600				Woodbend
0615221006000	95015	2	996	3459	3470	221985	138300	58879			8.0	156	3578	22890	370				Woodbend
0615262806000	95038	4	1158	3895	3953	168719	103750	44339			6.5	688	1823	17618	1020				Woodbend
0616020407000	95050	4	1313	4512	4555	157962	96192	41526			7.2	675	1847	16340	2810				Woodbend
0625262310000	96090	2	933	3594	3600	254931	157049	70396			7.1	228	2155	24314	767				Woodbend
0625263610000	96102	1	879	3531	-1000	254931	157049	70396			7.1	228	2155	24314	767				Woodbend
0625263612000	96104	4	872	3541	3546	254931	157049	70396			7.1	228	2155	24314	767				Woodbend
0626093409000	96192	1	1409	5243	5532	182816	111200	48898			7.6	82	1555	19059	4111				Woodbend
0635250510000	97249	1	899	3569	3572	254931	157049	70396			7.1	228	2155	24314	767				Woodbend
0635250512000	97250	3	883	3535	3543	242454	149926	65106			7.0	230	2261	24595	683				Woodbend
0635250512000	97250	2	883	3535	3543	254931	157049	70396			7.1	228	2155	24314	767				Woodbend

DLS	ID	#	elev	dtop	dbot	TDS	Cl	Na _c	K	pH	SO ₄	Mg	Ca	HCO ₃	Ca _{ex}	Na _{cl}	Na/Cl	Aquifer
0635250610000	97254	1	871	3514	3533	250588	154984	69245		7.0	246	2966	22739	830				Woodbend
0635250612000	97255	1	860	3494	3523	256914	159173	70147		7.1	220	3305	23715	720				Woodbend
0635250912000	97258	3	833	3493	3503	239868	148003	86358		6.8	249	2204	22599	927				Woodbend
0635251604000	97266	3	825	3417	3488	249160	153588	89318		6.3	241	1865	23715	879				Woodbend
0635260110000	97276	1	873	3528	3539	216164	133482	58167		6.8	213	1661	22320	653				Woodbend
0635260110000	97276	2	873	3493	3539	261924	161965	72099		6.8	206	2627	24692	683				Woodbend
0635260100300	97300	3	934	3589	3592	245567	150795	72323		7.2	336	1356	20367	793				Woodbend
0636010110000	97310	5	1012	3792	3819	256587	159000	69615		6.5	247	3036	24455	475				Woodbend
0666062212000	102445	3	785	3907	3916	171615	105400	51371		6.9	412	1116	13208	220				Woodbend
0675221806000	103542	1	719	2722	2739	234444	145200	62306		6.2	399	2819	23463	524				Woodbend
0675222010000	103543	4	701	2902	2926	192587	119000	51356		6.6	593	2540	18779	650				Woodbend
0675222070000	103550	1	676	2654	2655	278357	171835	76598		6.3	269	2708	26270	412				Woodbend
0675222707000	103550	4	676	2654	2655	278623	172000	76667		6.3	269	2710	26300	412				Woodbend
0676043210000	103599	10	693	3720	3755	271324	168400	71028		6.7	272	3177	28275	350				Woodbend
0685213214000	183296	1	654	2525	2534	184129	114000	47802		7.3	470	2240	19600	442				Woodbend
0685220407000	104465	2	679	2659	2672	169944	104730	44902		6.8	607	1952	17281	314				Woodbend
0685222301020	163678	3	659	2611	2618	190865	118000	50087		6.4	608	2410	19500	528				Woodbend
0685222303000	104473	1	658	2587	2601	254894	158200	68608		6.6	301	3118	26481	380				Woodbend
0685222713000	104497	1	676	2605	2612	248595	154000	63606		6.9	373	2890	27000	194				Woodbend
0685223307000	104501	1	688	2624	2628	249142	154299	64629		6.4	259	2916	26425	401				Woodbend
0685230801000	104525	8	792	2824	2833	229678	142992	57906		6.5	316	3549	24750	335				Woodbend
0685230801000	104525	6	792	2802	2809	229952	142992	56930		6.1	286	3045	26465	475				Woodbend
0685230801000	104525	9	792	2841	2852	230264	142992	58981		6.0	319	3003	24750	445				Woodbend
0685231207000	104528	1	715	2693	2705	235812	146800	57977		7.0	438	3937	26350	632				Woodbend
0685251314000	104540	4	754	2809	2817	217133	134422	56962		7.7	597	2634	22354	335				Woodbend
0685251314000	104540	8	754	3001	3031	233116	144306	65086		6.5	379	2900	20310	275				Woodbend
0695210704020	177883	2	650	2575	2605	210903	130866	52705		5.8	514	2848	23722	504				Woodbend
0695211804000	105419	1	646	2700	2705	196658	122000	51681		7.3	200	2240	20400	279				Woodbend
0695220407000	105451	2	685	2618	2619	246757	153400	63637		6.2	280	3548	25666	460				Woodbend
0695220915000	105458	1	679	2623	2626	207853	128646	50975		6.5	319	1452	26202	525				Woodbend
0695221011000	105462	1	672	2594	2602	237047	146973	59530		6.9	288	2982	26641	421				Woodbend
0695221615000	105493	1	693	2612	2622	249000	153755	62798		6.0	438	1865	29505	287				Woodbend
0695221615000	105493	2	693	2614	2624	269996	166759	73171		6.7	269	2845	26179	377				Woodbend
0695221615000	124881	0	693	2614	2624	192751	117863	59368		6.4	491	1494	12818	347				Woodbend
0695221901000	105499	1	717	2639	2646	232296	144978	56207		7.9	259	3920	26738	395				Woodbend
0695221905000	105501	1	737	2556	2567	231408	143600	61800		7.1	350	3164	22340	312				Woodbend
0695232413000	105517	5	746	2690	2697	218413	136000	55497		6.2	329	3777	22574	480				Woodbend
0665252115000	102407	2	738	3392	3396	172321	104500	61919	1220	6.5	1072	1337	3403	183	59	-134	0.903	Beaverhill Lake

DLS	ID	#	elev	dtop	dbot	TDS	Cl	Na	Na _c	K	pH	SO ₄	M	Ca	HCO ₃	Ca _{ex}	Na _{ex}	Na/Cl	Aquifer
0645190405000	122054	0	789	3041	3043	165913	103000	47725	50602	1420	6.3	364	1287	11590	527	469	290	0.758	Beaverhill Lake
0655152909000	100913	1	947	2823	2850	166174	102000	45237	43625	2736	6.9	1282	1944	15620	185	671	570	0.659	Beaverhill Lake
0635192312000	97152	1	794	3039	3051	244032	151000	84985	82540	4150	6.9	392	2440	25000	438	1087	932	0.639	Beaverhill Lake
0465173402000	64912	1	1298	4714	4717	178745	110300	50843	44401	10950	6.6	193	2090	14930	793	628	737	0.621	Beaverhill Lake
0445160212000	61037	5	1242	4870	4876	119344	74500	29596			6.6	74	2843	11930	817				Beaverhill Lake
0445162006000	61039	6	1191	4813	4820	120366	73400	36226			8.0	119	1108	8689	1676				Beaverhill Lake
0485190106000	71567	3	1116	4603	4615	149206	91063	46406			7.1	187	942	9875	1288				Beaverhill Lake
0495191015000	75215	2	1135	4469	4526	147832	91633	40051			7.0	163	2480	13123	776				Beaverhill Lake
0515163311000	81228	1	969	3698	3718	167220	102300	49672			6.6	570	1196	13072	834				Beaverhill Lake
0515172710000	81239	1	1003	3837	3847	191747	118000	53521			6.3	420	2579	16477	1525				Beaverhill Lake
0535150511000	83781	2	907	3402	3417	179302	109941	52169			6.7	54	475	16214	913				Beaverhill Lake
0535152204000	83785	7	927	3361	3366	173519	105790	51240			7.2	814	1409	13600	1354				Beaverhill Lake
0535200810000	83949	5	1036	4171	4209	181391	110099	50787			7.4	1164	1246	17079	2067				Beaverhill Lake
0545150507000	85102	1	891	3319	3366	189336	115800	56580			6.8	337	1385	14494	1505				Beaverhill Lake
0545151311000	85104	5	867	3255	3260	172346	106000	55934			6.7	74	1604	8625	222				Beaverhill Lake
0545152111000	85107	1	829	3217	3223	169889	106921	39815			5.7	352	5161	17482	322				Beaverhill Lake
0545152611000	85110	1	819	3180	3182	179172	112241	47091			6.3	83	4786	14717	517				Beaverhill Lake
0545162906000	85121	1	921	3399	3434	183057	112400	54401			7.0	241	935	14214	845				Beaverhill Lake
0545172807000	85136	4	924	3456	3485	183516	116000	66420			7.7	242	923	7728	4480				Beaverhill Lake
0545181210000	85166	1	969	3560	3584	196038	121000	53738			6.1	282	2432	18036	1120				Beaverhill Lake
0555161606000	87399	1	893	3296	3353	159850	96800	55399			6.7	538	622	5974	1050				Beaverhill Lake
0555192312000	87463	3	1081	3829	3841	194464	118436	49720			7.3	622	1775	22133	3611				Beaverhill Lake
0565180911000	89396	1	1129	3708	3734	215009	132600	57434			6.3	166	1555	22743	1040				Beaverhill Lake
0585181110000	91979	1	1225	3573	3594	211406	131238	52891			6.6	123	2750	23924	976				Beaverhill Lake
0585181306000	91981	1	1116	3490	3499	212585	131407	54535			7.1	178	2077	23795	1210				Beaverhill Lake
0585181910000	91983	2	1063	3431	3433	200859	123972	51860			7.0	169	2465	21488	1840				Beaverhill Lake
0585193606000	92017	3	1046	3438	3446	218311	134694	51327			6.8	382	2286	28460	1832				Beaverhill Lake
0595183110000	92875	1	871	3236	3239	233556	144600	62710			6.1	122	2552	23183	790				Beaverhill Lake
0605141907000	93680	1	794	2802	2817	188081	117055	44422			6.6	352	3302	22473	971				Beaverhill Lake
0605171607000	93743	5	796	2938	2966	173021	108822	45732			6.9	7	1546	18353	1142				Beaverhill Lake
0605172810000	93748	2	920	3045	3071	167297	102200	48268			6.9	648	1094	14535	1123				Beaverhill Lake
0605173305000	93750	5	922	3091	3095	185465	114159	53243			7.0	16	1257	16351	893				Beaverhill Lake
0605180507000	93756	2	862	3232	3264	239945	148400	64994			6.1	95	2163	23944	710				Beaverhill Lake
0605203311000	93833	3	908	3373	3392	198470	122913	51980			6.7	47	2239	20818	962				Beaverhill Lake
0615153007000	94870	1	907	2896	2917	184640	113400	53616			6.3	309	1239	15784	1000				Beaverhill Lake
0615170610000	94904	4	831	3176	3191	207328	128390	54695			6.9	53	2164	21625	815				Beaverhill Lake
0615171006000	94905	1	843	3011	3017	195121	120100	58652			7.0	249	1620	14320	366				Beaverhill Lake
0615172310000	94912	2	946	3092	3107	187176	115000	53370			6.6	451	1823	16016	1050				Beaverhill Lake

DLS	ID	#	elev	dtop	dbot	TDS	Cl	Na	Na _c	K	pH	SO ₄	Mg	Ca	HCO ₃	Ca _{eq}	Na _{eq}	Na/Cl	Aquifer
0615181307000	94923	2	889	3074	3085	169095	103877	47463			6.6	183	1576	15296	1425				Beaverhill Lake
0615182414000	140927	4	827	3027	3040	200576	123000	57613			6.9	376	1740	17100	1520				Beaverhill Lake
0615183512000	94936	1	832	3030	3062	205969	127300	59497			6.4	60	2090	16817	417				Beaverhill Lake
0615183605000	94937	2	869	3034	3070	213088	131500	61329			6.5	202	1944	17900	433				Beaverhill Lake
0615183607000	94938	1	881	3096	3109	153624	94160	42967			7.3	778	1630	13600	316				Beaverhill Lake
0615191902000	94953	5	897	3267	3273	210104	130207	50549			6.6	420	2270	26250	830				Beaverhill Lake
0615192803000	94965	1	918	3292	3300	224769	139082	58095			6.8	227	2403	24455	1030				Beaverhill Lake
0615213107000	95008	2	930	3491	3493	176049	108304	48915			6.4	63	1546	16527	1411				Beaverhill Lake
0625150406000	95795	3	920	2910	2925	171651	105451	48241			6.6	23	924	15511	1020				Beaverhill Lake
0625180910000	162675	1	983	3045	3048	182028	112000	51412			7.4	751	2895	14690	976				Beaverhill Lake
0625181110020	95834	1	907	3106	3114	211015	130000	60320			6.5	313	2428	18418	756				Beaverhill Lake
0625181310000	95839	1	875	3077	3104	193751	119122	55631			6.1	72	1580	18619	864				Beaverhill Lake
0625181310000	95839	4	875	3077	3104	203098	125100	59375			6.5	158	983	17519	888				Beaverhill Lake
0625190614000	95858	1	869	3223	3281	210383	130640	52098			6.8	155	2010	15900	232				Beaverhill Lake
0625200116000	95887	1	875	3231	3238	242502	149800	65335			6.2	243	2527	24575	610				Beaverhill Lake
0625202111000	95969	1	851	3214	3221	236224	146318	63195			6.1	206	2138	24585	890				Beaverhill Lake
0625202711000	95994	4	838	3196	3202	234388	145550	60692			6.7	229	3035	23012	886				Beaverhill Lake
0625203306000	96012	1	835	3188	3194	239478	148400	63974			7.8	10	2795	25000	693				Beaverhill Lake
0625231107000	96055	3	1005	3624	3639	238716	147400	63789			6.1	137	2673	23984	630				Beaverhill Lake
0625231107000	96055	1	1005	3624	3639	241465	149600	63266			7.5	213	2250	24370	460				Beaverhill Lake
0635142207000	97064	1	995	2812	2830	170122	102539	63097			6.1	232	2673	25345	710				Beaverhill Lake
0635200813000	97188	4	796	3203	3247	211353	130800	57163			6.6	957	374	2910	498				Beaverhill Lake
0645143202000	98440	4	1076	2869	2905	185088	111480	68720			7.0	187	2661	20100	898				Beaverhill Lake
0645191412000	98519	3	749	2961	2978	212136	131200	52994			6.2	1190	495	2960	495				Beaverhill Lake
0645192207000	98540	4	747	2986	3012	252979	157234	66489			7.2	374	4468	21700	2847				Beaverhill Lake
0665250211000	102401	2	793	3420	3455	204964	123600	75892			6.2	173	3108	25916	120				Beaverhill Lake
0575151201000	90771	4	939	3211	3222	209088	128455	64518	63044	2500	6.1	1160	461	3605	500	576	365	0.757	Elk Point
0625262609000	161564	0	896	3698	4181	229858	140590	60000	64888	4100	7.1	3325	1779	19462	602	822	578	0.712	Elk Point
0525141808000	82645	5	961	3495	3532	184706	113700	53934	51403	4300	6.3	572	1677	14770	106	616	514	0.697	Elk Point
0685211416000	104435	1	709	2926	2934	245866	151500	69534	67645	3206	5.7	815	2138	21860	39	930	722	0.688	Elk Point
0515172710000	81239	2	1003	3897	3918	177708	108000	52595			6.9	1267	903	14526	850				Elk Point
0565162404000	89377	1	939	3322	3363	203509	125775	55586			6.0	399	1984	19632	270				Elk Point
0595210115000	92909	3	1118	3854	3868	204562	127270	46453			7.6	384	2420	27790	500				Elk Point
0615151404000	94861	4	831	2897	2907	201636	125312	54018			6.7	69	3178	18750	630				Elk Point
0615182808000	94928	2	910	3231	3246	239878	148350	63751			7.4	247	2056	25193	570				Elk Point
0615191902000	94953	6	897	3372	3375	254165	158598	60248			6.6	700	4540	30000	160				Elk Point
0615191902000	94953	7	897	3372	3375	253651	158598	60079			6.6	370	4540	30000	130				Elk Point

DLS	ID	#	elev	dtop	dbot	TDS	Cl	Na	Na _c	K	pH	SO ₄	Mg	Ca	HCO ₃	Ca _{ex}	Na _{cl}	Na/Cl	Aquifer
0625181802000	95848	2	880	3296	3302	211584	131588	58148			7.2	25	3038	18736	100				Elk Point
0625191604000	95870	3	874	3252	3263	246694	154174	57545			6.4	173	3600	31160	85				Elk Point
0625212710000	96041	2	892	3410	3427	244019	152724	56195			6.4	168	4086	30750	195				Elk Point
0635161106000	97089	1	1049	3109	3120	247250	154160	60651			6.1	200	3350	28860	60				Elk Point
0635202802000	97195	3	787	3197	3205	265910	164472	71813			6.6	219	1855	27468	170				Elk Point
0635202802000	97195	4	787	3197	3205	272424	169367	72470			6.6	198	3710	26596	170				Elk Point
0635213210000	97210	4	771	3258	3272	268717	167444	62640			6.9	138	2590	35868	75				Elk Point
0635213210000	97210	5	771	3258	3272	250993	157234	56058			7.1	201	4144	33306	100				Elk Point
0655152202000	100911	1	993	2908	2922	255025	158960	64067			7.2	200	3800	27900	200				Elk Point
0655180110000	100931	5	803	2938	2954	265351	165015	71155			6.6	193	3930	24940	240				Elk Point
0655191110000	100954	1	812	3023	3028	265637	164472	72311			5.6	235	2385	26160	150				Elk Point
0655202006000	100976	3	743	3071	3086	287034	165502	71355			6.0	222	2436	27470	100				Elk Point
0655231810000	101015	4	846	3458	3469	263726	164200	65509			5.9	43	2935	30956	170				Elk Point
0665183204000	102318	2	765	2865	2883	252428	157900	63038			5.3	185	5020	26181	190				Elk Point
0665193506000	102328	1	760	2899	2902	258358	160140	68381			n/a	200	2230	27360	96				Elk Point
0665210910000	102346	2	760	3010	3038	242482	151000	57996			n/a	230	2685	30635	114				Elk Point
0675153010000	103452	2	956	2817	2821	263540	162700	77839			5.8	420	3330	23920	171				Elk Point
0675162607000	103460	2	943	2864	2874	256075	158000	74876			5.9	240	2360	20360	82				Elk Point
0675210210000	103526	6	748	3045	3060	267071	168400	70004			n/a	190	2070	25670	99				Elk Point
0675212815000	103533	6	707	2989	2997	256375	158820	69631			5.8	318	4540	25740	140				Elk Point
0675220815000	103537	4	704	3121	3126	258987	161000	64968			n/a	190	2320	25370	90				Elk Point
0675230809000	103559	5	776	3275	3284	261336	164838	53698			6.5	211	6072	36480	75				Elk Point
0685230801020	104526	1	790	3231	3231	241319	152922	46862			5.9	253	7320	33768	395				Elk Point
0685230806000	104527	1	789	3218	3227	264522	166100	53744			5.5	359	4613	39640	134				Elk Point
0635161106000	97089	2	1049	3456	3479	216584	134300	55487			6.4	175	1760	24780	167				Cambrian
0655202006000	100976	4	743	3171	3181	251911	157526	56228			6.0	267	3654	34170	135				Cambrian
0685262303000	102417	3	760	3536	3546	228823	143568	50311			6.0	440	4818	29602	170				Cambrian
0675222701000	103545	2	681	3090	3094	241113	150480	54671			n/a	170	2890	33070	66				Cambrian
0675222701000	103545	3	681	3113	3119	240506	149940	56440			n/a	150	2690	31230	114				Cambrian
0685170910000	104409	1	907	2972	3008	220669	136880	58676			5.4	480	2480	22280	149				Cambrian

**APPENDIX D: EQUATIONS FOR THE DENSITY CALCULATION OF FORMATION
WATERS (Rowe & Chow, 1970; Kestin et al., 1981)**

$$\rho^{-1} = A - B \cdot p - C \cdot p^2 + w \cdot D + w^2 \cdot E - w \cdot F \cdot p - w^2 \cdot G \cdot p - 0.5 \cdot w \cdot H \cdot p^2,$$

where ρ = density (kg/m³), p = pressure (MPa), T = temperature (°K), w = weight percent salinity (kg/kg)

The coefficients A to H are functions of temperature:

$$A = 1.00674 \cdot 10^2 T^{-2} - 1.127522 T^{-1} + 2.84851 \cdot 10^{-3} - 1.5106 \cdot 10^{-5} T + 9.270048 \cdot 10^{-9} T^2$$

$$B = 1.042948 T^{-2} - 1.1933677 \cdot 10^{-2} T^{-1} + 5.30753 \cdot 10^{-5} - 1.0688768 \cdot 10^{-7} T + 8.492739 \cdot 10^{-11} T^2$$

$$C = 1.23268 \cdot 10^{-9} - 6.861928 \cdot 10^{-12} T$$

$$D = -2.5166 \cdot 10^{-3} + 1.11766 \cdot 10^{-5} T - 1.70552 \cdot 10^{-8} T^2$$

$$E = 2.84851 \cdot 10^{-3} - 1.54305 \cdot 10^{-5} T + 2.23982 \cdot 10^{-8} T^2$$

$$F = -1.5106 \cdot 10^{-5} + 8.4605 \cdot 10^{-8} T - 1.2715 \cdot 10^{-10} T^2$$

$$G = 2.7676 \cdot 10^{-5} - 1.5694 \cdot 10^{-7} T + 2.3102 \cdot 10^{-10} T^2$$

$$H = 6.4633 \cdot 10^{-8} - 4.1671 \cdot 10^{-10} T + 6.8599 \cdot 10^{-13} T^2$$